

WYOMING MUNICIPAL POWER AGENCY



INTEGRATED RESOURCE PLAN

2007



July 31, 2007

PART I

INTRODUCTION

WMPA

The Wyoming Municipal Power Agency (WMPA or Agency) is the wholesale electricity provider for eight public power communities in Wyoming. WMPA is a body corporate and politic, and a public corporation of the State of Wyoming. The WMPA was created pursuant to the Wyoming Joint Powers Act by eight municipalities in Wyoming in order to provide for the financing, acquisition, and operation of power supply facilities and resources required to meet the electric power and energy requirements of member municipalities.

The Agency is governed by an eight person Board of Directors. Directors are appointed by resolution of the governing body of each member, serve for a three year term, and can be reappointed. Each Director has one vote and issues are decided by majority vote of the Board. WMPA's Board of Directors is responsible, as outlined in the Power Supply Contracts, to provide for all the electric energy needs of its members in the manner it determines is best, and can issue debt to finance projects to that end. Debt issued by the Agency is in the form of revenue bonds that do not constitute an obligation of the individual members, but rather of the Agency alone.

The seven original members of the WMPA are the City of Cody and the Towns of Fort Laramie, Guernsey, Lingle, Lusk, Pine Bluffs, and Wheatland. The City of Powell became a member of the Agency in 1986. Under the terms of the power supply contracts with the Agency, the members purchase all the electric power and energy required for operation of their electric utility systems from the Agency, at rates established by the Agency. The power supply contracts were renegotiated in 2005 and extend until February 1, 2048.

MEMBER SYSTEMS

The Agency's member systems range from small to very small municipal systems with essentially no industrial customers. Loads are primarily residential, "large" commercial (defined as customers with demand meters), small commercial (businesses with demands less than 25 Kw and no demand metering), and "other" loads that consists primarily of municipal load (such as street lighting, water pumping, etc). The following table provides a summary of the general characteristics of WMPA's member systems in 2005.

Table I - 1
Member Load
Characteristics

Member System	Demand MW	Energy MWhr	Percent Residential	Small Commercial	Large Commercial	Other Load
Cody	21.693	108,378	31.10%	14.22%	48.03%	6.64%
Ft. Laramie	0.298	1,376	74.53%	19.87%	0.00%	5.61%
Guernsey	2.354	11,419	42.45%	16.79%	23.94%	16.82%
Lingle	0.900	3,986	53.44%	37.36%	0.00%	9.20%
Lusk	3.142	15,622	39.28%	30.96%	25.21%	4.55%
Pine Bluffs	2.304	10,388	49.56%	17.39%	24.70%	8.34%
Powell	9.566	49,599	35.22%	14.13%	47.16%	3.49%
Wheatland	7.862	36,202	40.82%	12.59%	41.40%	5.19%
WMPA	47.975	236,970	35.94%	15.66%	42.23%	6.17%

RATES

WMPA's tariff to its members is broken out by services provided and further divided into demand and energy components. Demand and energy are billed on a monthly basis with the demand being measured at the transmission side of the delivery point and not ratcheted by season or annually. The Agency's existing tariff to its members is set forth below:

Generation Services:

Demand Charge	\$5.14 per Kw-mo.
Energy Charge	23.69 mills/Kwhr

Transmission Services:

Demand Charge	\$1.58 per Kw-mo.
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Member Services:

Energy Charge	0.18 mills/Kwhr
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Given the member average monthly system load factor of 66% and a total demand charge of \$6.72 per Kw-mo. and energy rate of 23.87 mills/Kwhr the average yield of the rate is approximately 37 mills/Kwhr.

RESOURCES

WMPA's generation capacity comes from its ownership share of the Missouri Basin Power Project (MBPP), which includes the Laramie River Station (LRS) in Wheatland, Wyoming, a long-term firm power supply contract with Basin Electric Power Cooperative (Basin), contracts to purchase federal hydropower, and spot purchases to meet load.

The Agency entered into an initial Master Contract for Electric Service and Transmission Service with the Western Area Power Administration (Western) effective May 26, 1978. This contract provided that the Agency purchase from Western for the member municipalities all federal hydroelectric power and energy originally allocated to those municipalities. The 1978 contract was superseded by separate contracts for federal hydropower from Loveland Area Projects (LAP) and Salt Lake City Area Integrated Projects (SLCA/IP) which extend until the year 2024, a Network Integrated Transmission Service contract, and a Consolidated Facilities contract. Western acts as the scheduling agent for WMPA resources and coordinates with Agency staff for the efficient allocation of energy among available resources to minimize power costs to the members.

STUDY

As a customer of Western, the Agency is subject to certain requirements to prepare studies of its resource needs for the future and develop supply and demand side options to meet those requirements – the Integrated Resource Plan (IRP). WMPA, working with R. W. Beck and Associates, developed a forecast of loads for the Agency, which is described in Part II. Using the forecast of demand and energy and considering the existing resources and their operational limitations developed an optimized model for dispatching existing and future resources to meet load. The existing system is described in Part III. Demand side options for consideration are reviewed and described in Part IV. Supply side options for consideration are reviewed in and described in Part V. Plans for meeting the resource needs of the Agency for the next 20 years are developed and discussed in Part VI.

PART II

SYSTEM LOAD FORECAST

To reasonably forecast future resource requirements, it is critical to carefully estimate the Agency's rate of growth and project member loads that must be met. This section of the IRP establishes the Agency's rate of future growth based on a weighted averaging of historical loads from 1985 to 2005 and the estimated impact of economic outlooks of member systems. Loads are then forecast from 2006 to 2025; though we would caution the reader against placing too much faith in the absolute values of our projections beyond a seven to ten year horizon. Never the less, projections beyond the ten year time frame are necessary to provide broad guidance in establishing levels of generation needed to meet such anticipated loads.

The Agency's coincident load forecast includes loads for the following communities:

- ❖ Cody
- ❖ Fort Laramie
- ❖ Guernsey
- ❖ Lingle
- ❖ Lusk
- ❖ Pine Bluffs
- ❖ Powell
- ❖ Wheatland

METHODOLOGY

The forecast was developed by using simple linear regression analysis on the sum of historic energy data of the Agency's members; with greater weighting given to the last five years of data, and modifying the result by averaging historic trends with forecasts of probable economic growth for each member. Future coincident demand for the Agency was estimated by applying the same rate of growth as that calculated for energy and using a smoothed number for the 2005 starting point.

ENERGY

Applying this methodology to historic data yields a growth rate of 2.6% per year. The resulting forecast is shown in Table II-1 and Chart II-1 and produces energy consumption by members of 247,629 MWhr in 2006 rising to 427,150 MWhr in 2025.

DEMAND

Forecast coincident demand created by using the above technique yields a result that increases from 46.4 MW in 2006 to 76.3 MW in 2025. Year by year historic and calculated values are shown in Table II-1 and Chart II-2. This is the anticipated demand at the members delivery points and does not include any adjustment for system losses or reserve requirements of the Agency as a member of the Rocky Mountain Reserve Group. Reserve obligations are expected to increase from 2 MW in 2006 to 3 MW in 2025.

Table II-1

Historic and Forecast Demand and Energy

<u>Year</u>	<u>MW</u>	<u>MWhr</u>
1985	29.0	154,507
1986	28.1	152,284
1987	28.4	156,549
1988	29.4	164,211
1989	31.4	171,593
1990	34.8	166,535
1991	30.8	168,797
1992	31.2	169,607
1993	31.4	173,556
1994	31.0	179,594
1995	33.5	183,870
1996	34.6	195,012
1997	34.8	195,031
1998	37.1	199,701
1999	36.6	200,710
2000	37.7	209,352
2001	39.7	213,695
2002	40.5	218,941
2003	45.0	235,710
2004	41.9	230,738
<u>2005</u>	<u>45.7</u>	<u>236,970</u>
2006	46.4	247,629
2007	47.6	254,067
2008	48.9	260,673
2009	50.2	267,540
2010	51.5	274,404
2011	52.9	281,539
2012	54.3	288,859
2013	55.7	296,369
2014	57.2	304,075
2015	58.7	311,980
2016	60.3	320,092
2017	61.9	328,414
2018	63.5	336,953
2019	65.2	345,714
2020	66.9	354,720
2021	68.7	363,925
2022	70.5	373,387
2023	72.4	383,095
2024	74.3	393,055
2025	76.3	403,275

CHART II – 1

Energy Consumption - MWh

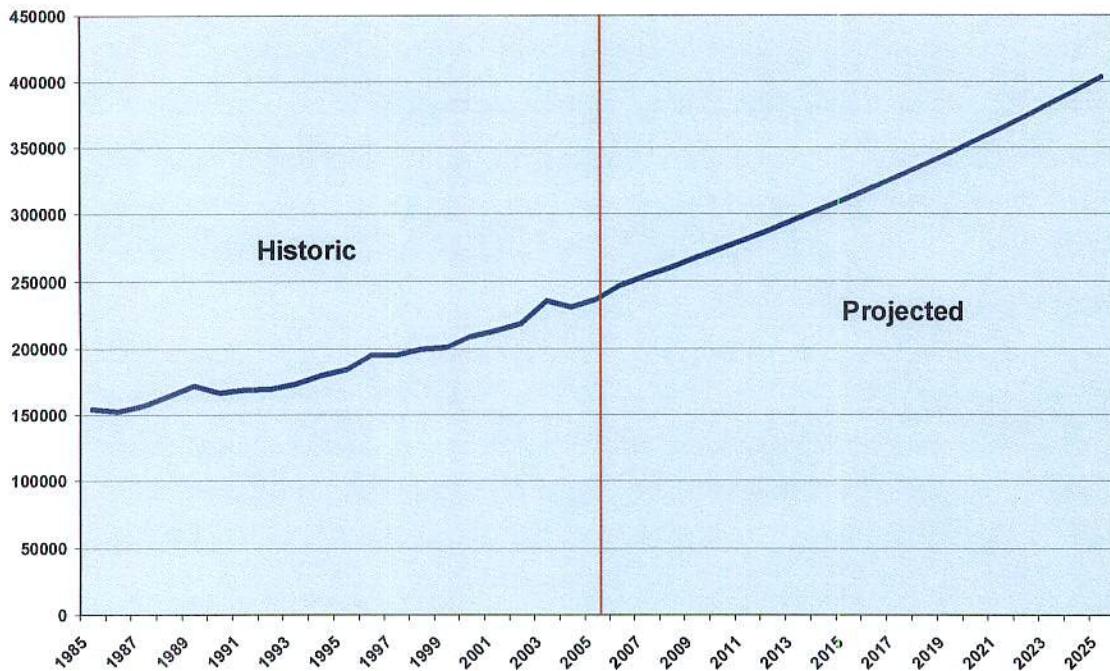
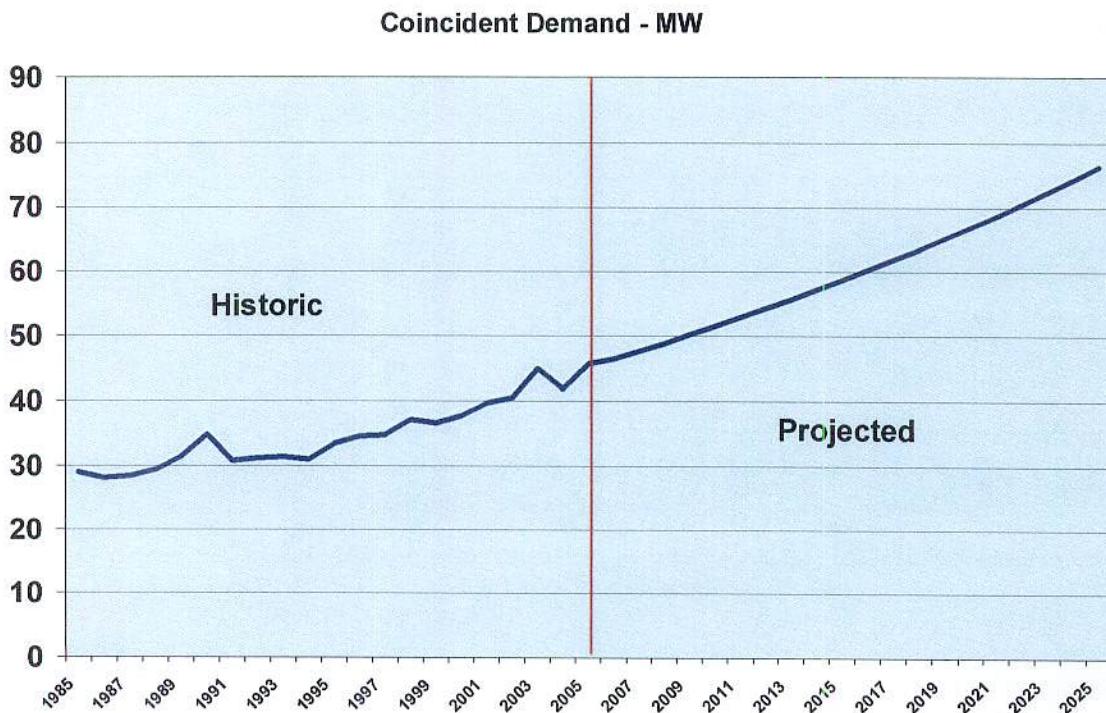


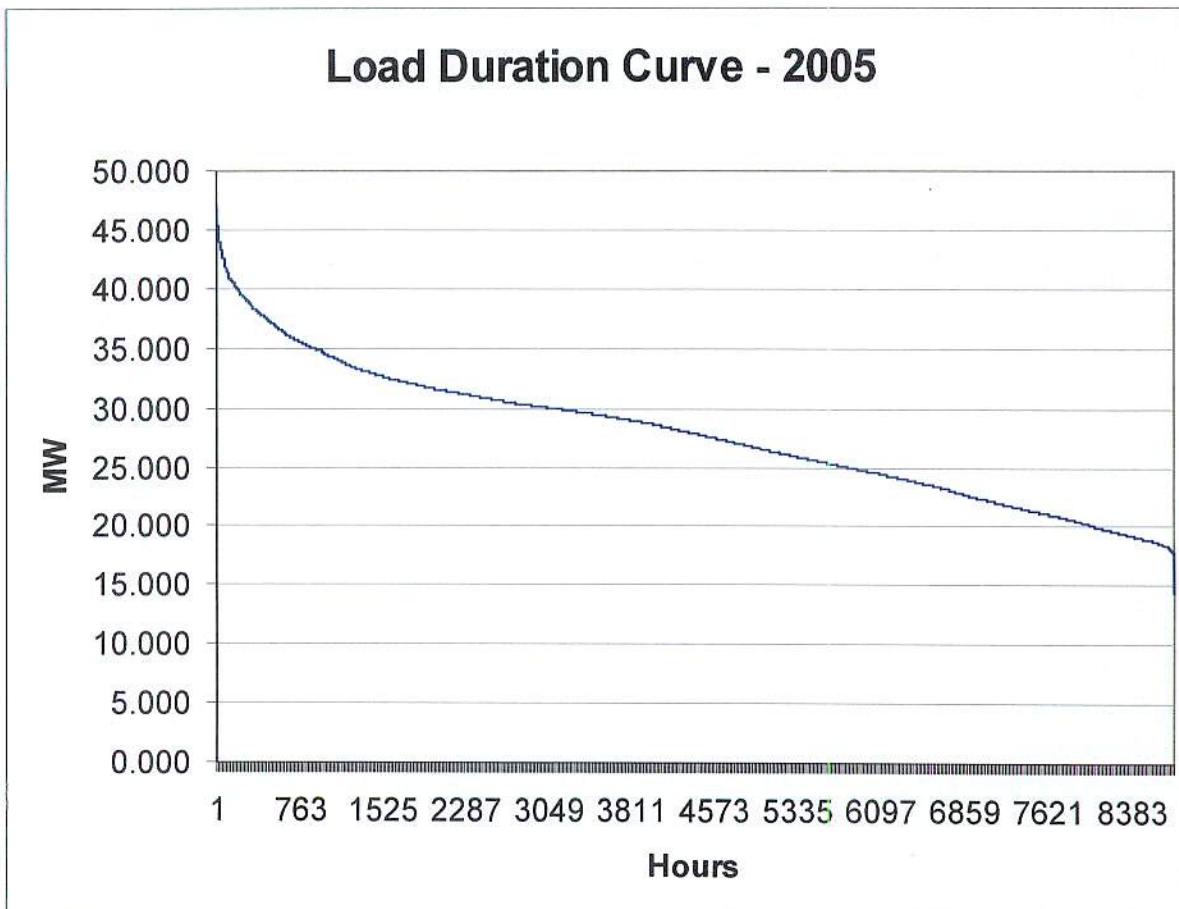
CHART II – 2



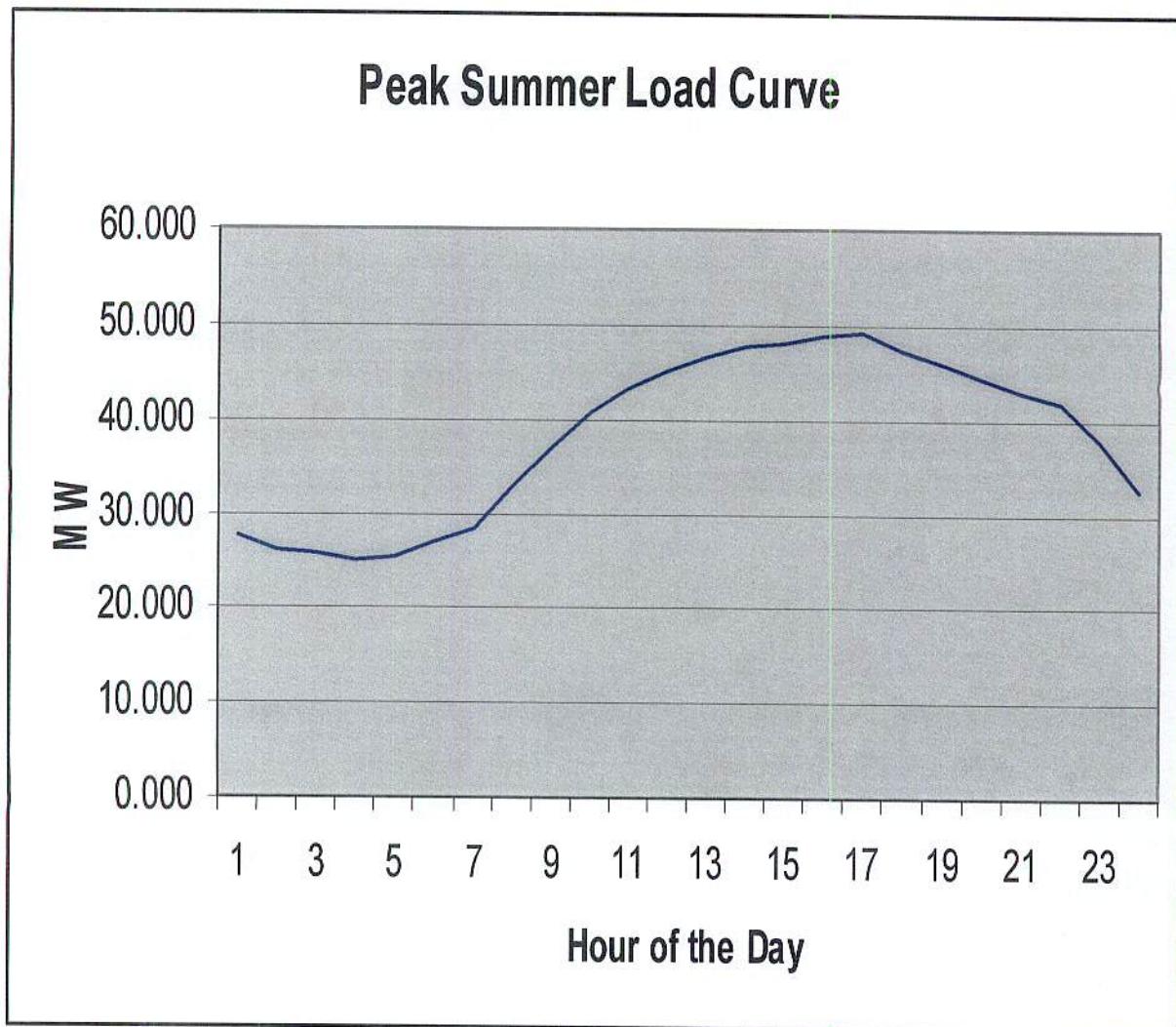
LOAD CHARACTERISTICS

WMPA's load is characterized by a relatively high monthly and annual load factor. This can be seen in the following graphs of the annual load duration curve and a typical load curve for a peak summer day. It should be noted that the values plotted represent the coincident load of the Agency's members as seen from the transmission system.

GRAPH II – 1



GRAPH II – 2



PART III

EXISTING AND COMMITTED LOAD AND RESOURCES

EXISTING RESOURCES

The Agency's existing resources base consists of its undivided ownership share in the Missouri Basin Power Project, contracts for Federal Hydropower from two projects, the Loveland Area Project (LAP) and Salt Lake City Area Integrated Project (SLCA/IP), a firm power contract with Basin Electric Power Cooperative for increasing block amounts until June, 2010, and spot market purchases to meet load. Some surplus sales are made when resources exceed load.

Resources are scheduled by the Western Area Power Administration – Montrose Office on behalf of and in consultation with the WMPA. Surplus power is sold through and marketed by the Rocky Mountain Generation Cooperative when available. System reliability obligations are met through membership in the Rocky Mountain Reserve Group and the Agency is obligated to carry its share of operating reserves.

MISSOURI BASIN POWER PROJECT

The Missouri Basin Power Project (MBPP) is coal-fired thermal plant, cooling water reservoir (Grayrocks Dam), and associated EHV transmission system to interconnect the generation to the regional power grid. It consists of three 550 MW (nominal) net rated generation units which became operational between 1979 and 1981. Two units (#2 and #3) are connected to the western interconnection while unit #1 is connected to the eastern interconnection; therefore the Agency functionally receives all its power from units #2 and #3. The MBPP generation units have had ongoing capital improvements and life extension activity and are expected to remain operational throughout the study period.

The Agency's ownership share of the MBPP is 1.37%, or 22.6 MW of capacity. Energy output from the MBPP is determined each year from the participant's estimates of their expected requirements. Actual monthly output varies by unit and is a function of unit availabilities. Recent drought conditions have adversely affected Grayrocks Dam storage, which is currently being supplemented with pumped groundwater. Costs are based on the annual operations budgets and are allocated to the members according to their entitlement share, scheduled energy, and heat rate data. Energy and capacity delivered to the WMPA over the Federal System are subject to wheeling fees and losses of 5%; except for the Town of Wheatland which is served from the MBPP transmission system and incurs no wheeling and 3% losses.

Salt Lake City Area Integrated Project

The WMPA has a contract with Western for capacity and energy from the SLCA/IP. The Contract Rate of Delivery (CROD) is 4,683 kW summer and 6,260 kW winter. The contracts also have a minimum which is around 1,000 kW summer and winter. The delivery rate for power made available to the Agency per month is based on the Long-term Sustainable Hydro Power (Long-term SHP) calculated by Western and based on actual and forecast hydrologic conditions on the Colorado River system. The Long-term SHP has replaced the CROD amount as the schedulable amount under the contract and is severely limited in its ability to follow load.

Loveland Area Project

The Agency also has a contract with Western for power from the Loveland Area Project (LAP or PS-LAP). The CROD varies on a monthly basis and the actual capacity benefit from the resource is limited by the average amount of energy available to be scheduled within a month. However, there is some flexibility afforded under the LAP contract in that additional capacity can be scheduled during higher load days. Maximum CRODs

vary from 13,549 kW in the winter season to 11,980 kW in the summer season. Unlike SLCA/IP, there are no wheeling charges or wheeling losses associated with deliveries from the LAP.

Mount Elbert Pumped Storage

As a part of LAP, the WMPA has a contract with Western for storage of off-peak energy in the Mt. Elbert pumped hydro storage facility. This agreement allows the Agency to move off-peak energy from light load hours (0000 – 0700) to peak hours (0800 – 2300). The account must be zeroed on a seasonal basis. The storage ratio is 1.4; that is, for every 1 MWhr returned on-peak, the Agency must deliver 1.4 MWhr off-peak. When wheeling losses in both directions are factored into the equation, the final delivery/return ratio is 1.6:1. All Mt. Elbert transactions fall under the LAP allocation and thus deliveries from LAP plus Mt. Elbert cannot exceed the monthly CROD under the LAP contract. These transactions are subject to the prevailing wheeling charge in both directions.

Basin Contract

On February 3, 2003 the Agency entered into a contract for firm electric service with Basin Electric Power Cooperative. The contract is effective from January of 2004 to June of 2010 and provides for varying blocks of firm capacity beginning at about 2 MW and increasing to about 9 MW at the end of the contract term. Basin is providing a delivery point on the Western LAP transmission system for delivery to Agency load. This contract is expected to terminate before the commercial operation of Dry Fork Station (DFS) and the Agency recognizes the need to negotiate a bridging contract with Basin, or another area utility, to span the gap in time between the expiration of this contract and the reliable operation of DFS. The contract is for a fixed price for the entire term of the purchase.

Dry Fork Station

In accordance with the recommendations of the Agency's 2001 Integrated Resource Plan, conducted by Burns and McDonnell, and a follow-up resource study conducted by R. W. Beck and Associates in 2005, the Agency has committed to 7.1%, or approximately 25 MW of a mine mouth, coal fired, air cooled, thermal power plant to be located near Gillette, Wyoming and called the Dry Fork Station (DFS). DFS is to be owned by Basin Electric Power Cooperative (Basin) and the Agency and operated by Basin. Coal is to be supplied by the Dry Fork Mine (DFM), owned and operated by Western Fuels Association (WFA) which also supplies coal to the Missouri Basin Power Project. Energy costs for this resource are expected to be extremely competitive and less volatile than generating facilities which depend upon rail transportation of coal to operate. Permitting of, and procurement for this facility has already begun. Commercial operation is expected in early 2011. Data related to capital, O&M, and energy related costs, as well as anticipated unit availability are contained in the cost modeling of the "Operating Result Projections" contained in Attachment "A" and are considered to be proprietary and confidential. The affect of DFS on the Agency's projected load and resource balance are shown in Table III – 1.

Reserves

The WMPA has a reserve sharing agreement with the Rocky Mountain Reserve Group (RMRG). The RMRG is a group of utilities who have shared reserved to provide lower cost backup capacity during outages of resources owned by the members. Each member is allocated reserve requirements based on its generation, largest hazard, and fuel mix. Currently the Agency purchases its reserve obligations from Western Area Power Administration and this is not expected to change during the period of this study.

Load and Resource Balance

The Agency's projected loads and anticipated resources are shown in tabular form in Table III – 1. Loads and resources were modeled on an hourly basis to adequately reflect the affect the character and limitations of each resource when optimally utilized to meet load. The base load nature of the MBPP and DFS resources were integrated with the more flexible nature of LAP, SLCA/IP, the Basin Purchase, and spot market purchases to meet load as economically as possible, minimize purchases, and maximize sales.

Table III – 1

		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
RESOURCES:																					
Normal LRS	MW	23	23	22	23	22	23	22	23	22	23	22	23	22	23	22	23	22	23	22	23
MWh	181,332	168,691	162,149	181,332	162,122	167,008	171,811	165,296	158,110	179,621	158,110	165,296	171,811	165,296	158,110	179,621	158,110	165,296	171,811	165,296	
Emergency LRS	MW	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Dry Fork	MW					25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
MWh	32,993	31,626	31,626	31,545	31,312	31,312	31,312	31,312	31,231	31,231	30,999	30,999	30,999	30,999	30,999	30,999	30,999	30,999	30,999	30,999	
PS-LAP	MW	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
MWh	18,383	18,770	19,165	19,566	19,566	19,566	19,566	19,566	19,566	19,566	19,566	19,566	19,566	19,566	19,566	19,566	19,566	19,566	19,566	19,566	
LAP Support	MWh	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
SLCIP	MW					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MWh	27,096	46,512	59,496	53,328	34,824	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Contracted Purchases	MW	5	5	9	7	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Spot Market	MW	6	7	5	8	10	0	0	0	0	1	2	3	6	6	9	10	13	14	17	18
TOTAL RESOURCES	MW	50	51	52	54	55	64	63	64	63	65	65	67	69	70	72	74	76	78	80	82
MWh	271,037	280,998	289,667	295,843	304,087	367,361	408,839	402,324	395,089	416,338	395,021	402,257	408,872	404,643	400,074	417,695	408,047	418,248	429,554	438,436	
LOAD:																					
MW	46	48	49	50	52	53	54	56	57	59	60	62	64	65	67	69	71	72	74	76	
MWh	247,629	254,067	260,673	267,450	274,404	281,539	288,859	296,369	304,075	311,980	320,092	328,414	336,953	345,714	354,702	363,925	373,387	383,095	393,055	403,275	
Losses	MW	2	2	2	2	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	
Losses MWh	9,990	10,361	10,672	10,994	11,333	11,668	12,012	12,365	12,731	13,115	13,496	13,887	14,289	14,700	15,123	15,556	16,001	16,457	16,926	17,437	
Reserves	MW	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	
Mt Elbert Losses	MWh	6,420	6,420	6,420	6,420	6,420	6,420	6,420	6,420	6,420	6,420	6,420	6,420	6,420	6,420	6,420	6,420	6,420	6,420	6,420	
TOTAL LOAD	MW	49,1	50,4	51,7	53,1	54,5	56,9	58,4	59,9	61,5	63,1	64,7	66,4	68,1	69,9	71,7	73,5	75,4	77,4	79,4	81,5
MWh	264,039	270,848	277,765	284,865	292,157	299,627	307,291	315,154	323,226	331,515	340,008	348,722	357,662	366,834	376,245	385,901	395,808	405,972	416,401	427,131	
SURPLUS:																					
MW	0.9	0.6	0.3	0.9	0.5	7.1	4.6	4.1	1.5	1.9	0.3	0.6	0.9	0.1	0.3	0.5	0.6	0.6	0.6	0.5	
MWh	6,998	10,150	11,902	10,978	11,930	67,734	101,548	87,170	71,863	84,823	55,013	53,536	51,211	37,809	23,828	31,794	12,239	12,276	13,153	11,305	

PART IV

DEMAND SIDE MANAGEMENT

The Agency has been engaged in producing Integrated Resource Plans every five years since 1992. As a result of the recommendations of these studies, several demand side projects have already been undertaken and are no longer considered fertile ground for the WMPA, or its members, to pursue. Examples of demand side conservation efforts in past years are:

- ❖ Over a two year period, beginning in 1994, the Agency provided its members with some 3,000 compact fluorescent lamps that were given away to residential customers when they came into pay their utility bills. Some members reported difficulty in finding sufficient interest from customers toward the end of the program. Compact fluorescent lamps are now much more readily available from retail vendors and make a good economic choice for end users. Estimated energy savings is 348.3 MWhr/year. Total cost was \$42,158.
- ❖ H.P.S. street light conversion program. From 1994 through 1996, WMPA entered into a program to pay for one half of the cost to replace existing mercury vapor street lights with more energy efficient high pressure sodium fixtures. Member participation was very good with essentially 100% of the old fixtures being replaced under this program. All new fixtures purchased for roadway illumination are of the H.P.S. type, so no reason exists to continue the program. Estimated energy savings is 215 MWhr/year. Program cost to the Agency was \$20,683.
- ❖ In 1994 and 1995, the WMPA made available an energy efficiency consultant to audit commercial and residential end users who requested the service. Requests were made through the member system with the Agency providing the expertise. Unfortunately, the program saw very little use and those that had the audit did not seem to follow through on the recommendations. Estimated energy savings – 1 MWhr/year. Total cost to provide the audits - \$7,310.

- ❖ The Agency's Board of Directors, and by implication our members, adopted a net metering policy in 2002. Neither the WMPA nor its members are required by statute or administrative procedure to provide for net metering, but have done so voluntarily in an effort to provide the best possible environment for the advancement of alternative energy technologies. To date, there are three sites operating under the net metering arrangement; all are solar installations and less than 5 kw in size. To qualify for net metering, the total installed generation must be less than 25 kw. Energy purchased in 2006 was about 1 MWhr. The Agency expects this program to grow dramatically during the next ten to twenty years, but remain at overall levels that do not significantly affect total load or our calculated rate of load growth.
- ❖ In 2005 and 2006, the WMPA replaced its outdated delivery point recorder system with a state of the art metering package that greatly expands the potential for future energy and demand conservation activities. These new meters allow for precise measurement of such fundamental system parameters as real-time voltage and current phase balance, power factor, and total harmonic distortion. While it is very difficult to quantify, there will be definite energy savings from the ability to more precisely balance loads and maintain high power factor on the respective distribution systems. But the new meters contain another ability, and that is to act as a gateway to control the substation bus voltage. This would allow the Agency to engage in a program of Conservation Voltage Reduction to reduce system peak demand. In order to do so effectively, commands to reduce voltage would have to originate with the Agency and be based on our composite load curve. In 2005 the Agency renegotiated its power supply contracts with its members to, among other things, extend the effective date to the year 2048. The new contracts contain a clause giving the Agency the necessary authority to pursue Conservation Voltage Reduction, if it becomes economically feasible to do so. Cost of the new metering package was \$164,268.

DEMAND-SIDE MANAGEMENT STUDY

R. W. Beck was retained by the Agency to perform an evaluation of the cost-effectiveness of residential and commercial demand-side management measures that could realistically be implemented by WMPA. This evaluation is included as Appendix B to the IRP.

The technical screening assessment identified fourteen potential DSM measures that were further evaluated through an economic screening analysis. Cost effectiveness evaluations were performed for three different perspectives: utility cost test, rate impact measure (RIM) test, and total resource cost (TRC) test. WMPA has established that a DSM measure must pass both the Utility Cost Test and the RIM Test before it will be promoted as a viable DSM activity in this IRP.

None of the DSM measures evaluated for economic potential were found to pass both the Utility Cost and RIM Test criteria. As such, WMPA is not including any projections of DSM impacts in this filing.

Please see Appendix B for a complete discussion of the evaluation process and its conclusions.

EXISTING AND PROJECTED OPERATING ENVIRONMENT

The Agency produces, on a periodic basis, a document entitled “Operating Results Projections” (ORP) that incorporates load, resource, and financial data for existing and committed resources as well as projected loads. This study is our primary planning tool and is used to examine the impact of various generation and transmission options on the WMPA’s wholesale rate to its members. A copy of the latest ORP which includes a 25 MW purchase of DFS is included as Appendix “A” and is considered confidential because of an agreement with Basin on matters relating to Dry Fork Station. In addition, the WMPA retained R. W. Beck and Associates to conduct an independent study of the relative economics of several possible future generation scenarios, including the purchase of an undivided ownership share of the Dry Fork Station. Beck’s PowerPoint presentation to the Agency’s Board of Directors is included as Appendix “B” and is considered proprietary for the same reason as that given for the OPR. The Agency, as noted earlier, has a binding agreement for 7.1% of DFS which should be about 25 MW during the peak summer month.

Incremental energy production at MBPP is very low, at around 13 mills/kWhr. For 2006 the Agency’s average purchase price for spot market energy was 50.77 mills/kWhr. Anticipated incremental energy production from DFS should be in the 15 mill/kWhr range because it is a mine mouth facility. Examination of the Table III – 1 reveals that the Agency is energy and capacity deficient from 2006 through 2010. From 2011 to 2016 the WMPA should be both capacity and energy sufficient with some surplus to sell. From 2017 to the end of the study the Agency is primarily capacity deficient. This does not mean that no energy will be purchased during those times when we are capacity and/or energy sufficient as unit outages and other operating conditions will require the purchase of small amounts of energy throughout the study period.

Several factors were considered when examining potential demand side programs for application to the Agency and its members:

- ❖ The relatively small size of the WMPA and its members. Neither the Agency nor its members have significant staff or operating resources to apply to any particular project; therefore, simpler is better and most effective.
- ❖ Real time pricing information is not now nor likely to be available. This is due to the lack of real time operation of the Agency. Our real time functions are contracted to the Western Area Power Administration at Montrose, CO. Further, the WMPA lacks communication infrastructure to make real time metering a cost effective reality.
- ❖ In order for demand side capacity projects to be of interest, they must be at least 1 MW in size. This is because 1 MW is the lowest incremental amount of capacity that can be scheduled in the load control area. There appeared to be few demand side activities that would produce the necessary level of dependable capacity reduction on a schedulable basis, other than Conservation Voltage Reduction.
- ❖ There would seem to be some opportunity to employ limited renewable energy technologies in the period from 2006 to 2010. The incremental cost of energy in the spot market is sufficiently high (50.77 mills/kWhr in 2006) to give serious consideration to appropriate technologies. After 2011 however, the incremental cost of energy from DFS is expected to be very low and very few, if any, conservation activities seem to make economic sense.
- ❖ The Agency's earlier efforts in conservation continue to produce small and ongoing energy savings; thought their cost-effectiveness is highly suspect as can be seen from the numbers earlier in this document. Essentially, most the low hanging fruit has been taken by earlier efforts.

RECOMMENDED ACTIVITIES

The Agency believes there are several conservation related activities that, given our particular operating environment and costs, would be advisable to consider implementing.

- ❖ Conservation Voltage Reduction (CVR) – The WMPA should examine closely the timing and economics of implementing a CVR program. Such a program would have to be implemented with the involvement and overview of our member systems, as reducing the bus voltage can cause detrimental and unacceptable voltage levels at extended points on the distribution system. A 2% reduction in load is, we believe, a realistic goal for CVR based on member system configurations. In order to achieve a 1 MW reduction in load, the Agency's total load would have to be at or above 50 MW. The Agency should achieve that level in 2007. However, not all of the WMPA's delivery points have the ability to easily implement CVR because not all delivery points have voltage regulation on the bus. Therefore, when loads are at or above about 55 MW (around 2010), such a system could be a cost effective tool to avoid the purchase of on-peak capacity. A study should be undertaken in 2008 to evaluate the costs and benefits of CVR and begin the implementation if found to be effective.
- ❖ Wind Generation – Given the nature of the Agency's service territory, the possibility of developing wind resources should be examined. Though wind power is, at least in the quantities likely to be applicable to the Agency's load, not a reliably schedulable quantity, with 50.77 mills/kWr as an average spot market purchase price, it could be economical. The study should examine outright ownership of up to two MW of wind capacity, possible benefits from allowing others to construct & operate the facility with the Agency making a long-term purchase agreement, or the use of a Renewable Energy Certificate program, such as the "Green Power Partnership" program operated by Western, as an alternative.

This study should be initiated as soon as possible as the economics appear to be favorable now.

- ❖ Examine the possibility of expanding the Agency's web site – www.wmpa.org – to include a more comprehensive section devoted to conservation. While this may seem a likely activity, we must point out that the web site has very little traffic and is not expected to significantly increase from the introduction of an expanded conservation section. This should be an ongoing activity for the duration of the study period.
- ❖ Distributed Generation Study – The Agency should conduct a survey of its member systems to determine the amount of distributed generation that already exists on our systems, the nature of the generation, establish individual members and their customers willingness to participate in a program to utilize such generation to offset WMPA peak load requirements, and quantify the costs and benefits of instituting a formal program. This program would be most effective between now and 2011 and again in the post 2015 time frame. It appears that the most useful mechanism would be a contractual agreement to run generation for up to some maximum period of time, when called upon by the Agency, in return for which a customer would receive a capacity credit for participating in the program.

PART V

SUPPLY SIDE OPTIONS

As discussed in Part III, the Agency has committed to a 7.1% (~25 MW) share of the Dry Fork Station; a mine mouth generation facility to be located near Gillette, WY which is expected to be operational in 2011. With its share of MBPP, Federal Hydropower contracts, existing firm power contract, and the anticipated output of DFS, the Agency has little need for traditional supply side projects until at least 2016. In the post 2016 time frame, the need will be for peaking and intermediate load range resources; some of which could be met with CVR, distributed generation contracts, or other appropriate demand side projects.

In short, the study recommends no immediate action on the supply side. This could dramatically change if Dry Fork Station is not constructed as currently anticipated. Because supply side options for intermediate to peaking range generation resources tend to involve shorter planning and development horizons than base load facilities, the study assumes a fresh look at supply side options will be made in the 2013 to 2015 time frame when the economic environment will be more clearly defined for such resources. Indeed, a new Integrated Resource Plan will be required by Western before the Agency will need to commit to new supply side resources.

PART VI

RESOURCE PLAN

PUBLIC INVOLVEMENT

An aspect of the integrated resource plan is to involve the public in the process. The Agency set up a meeting at its headquarters building in Lusk, WY on October 3, 2007, and invited the public to participate by advertising the meeting date and location in all member newspapers. There was no participation in the public meeting and no comments were offered.

FIVE YEAR PLAN

As a result of committing to ~25 MW of Dry Fork Station capacity, as anticipated in the 2001 Integrated Resource Plan, the Agency has little need in the next five years to engage in any additional supply side activities. This assumes, of course, that the Dry Fork Project is completed and operated as anticipated. A lengthy delay or cancellation of DFS will require a complete rethinking of these supply side conclusions.

The Agency should engage in the following demand side activities over the next five years:

- Commission a study to examine the costs associated with implementing a Conservation Voltage Reduction program using the newly installed meters as a communication and control gateway. The study should compare the cost of program implementation with any anticipated savings from reduced on-peak

purchases of spot market energy and capacity. This study should be completed in the next 12 months.

- Wind Generation/Renewable Energy Certificate Program. Within the next 18 months, the WMPA should work with its members and Western to:
 - Assess the retail level demand and willingness to pay for renewable energy products.
 - If sufficient demand and interest exists, an in-house examination of how to best implement such a program should be undertaken.
 - A comparison of the relative costs and benefits of Agency ownership vs. long term contract vs. Western's Green Power Program should be completed if the decision is made to proceed with offering additional "green power", i.e. more than the 25% of hydro that we now offer, is desirable.
- The Agency's web site should be reviewed for adequacy as a conservation resource. Addition material and links to outside resources should be implemented if deemed appropriate.
- Within 24 to 36 months, the WMPA should assess the benefits of a Distributed Generation Program. Because this activity involves retail level customers, Agency member systems will need to be deeply involved in shaping the program, identify relevant customers, and approving the end product. If less than 1 MW of potential exists within the Agency, the program should be deemed not feasible; because as stated before that is the minimum schedulable quantity in the load control area.

TEN YEAR PLAN

Beginning on or about 2013, the Agency should, with the help of an outside consultant, examine appropriate peaking and intermediate range generation resource options to address the anticipated capacity shortage. This examination should also include the possibility of expanding the CVR and Distributed Generation programs and new demand



side technologies that may be able to offset the need or reduce the amount of supply side expansion.

25 MW Dry Fork Case Prepared Nov 2005

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
9/3/2008 8:35										
RESOURCES										
These are based on the July loads and resources.										
Normal LRS MW	23	23	22	23	22	23	22	23	22	23
MWh	181,332	168,691	162,149	181,332	162,122	167,008	171,811	165,296	158,110	179,621
Emergency LRS MW	1	1	1	1	1	1	1	1	1	1
Dry Fork MW										
MWh										
PS-LAP MW	12	12	12	12	12	12	12	12	12	12
MWh	32,993	31,626	31,626	31,545	31,312	31,312	31,312	31,312	31,231	30,999
LAP Support MWh	0	0	0	0	0	0	0	0	0	0
SLCIP MW	3	3	3	3	3	3	3	3	3	3
SCLIP MWh	18,383	18,770	19,165	19,566	19,566	19,566	19,566	19,566	19,566	19,566
SCLIP Off Peak Replacement MWh	0	0	0	0	0	0	0	0	0	0
WRP (total 5,036 kW SCLIP) MW	0	0	0	0	0	0	0	0	0	0
WRP Energy (MWh)	0	0	0	0	0	0	0	0	0	0
Actual AHP Energy										
Contracted Purchases MW	5	5	9	7	7	0	0	0	0	0
MWh	27,096	46,512	39,496	53,328	34,824	0	0	0	0	0
Spot Market MW	6	7	5	8	10	0	0	0	0	0
MWh	11,233	15,399	17,231	10,072	56,263	40,336	0	0	0	0
TOTAL RESOURCES										
MW	50	51	52	54	55	64	63	64	63	65
MWh	271,037	280,998	289,667	295,843	304,087	367,361	408,839	402,324	395,089	416,338
LOAD:										
MW	46	48	49	50	52	53	54	56	57	59
MWh	247,629	254,067	260,673	267,450	274,404	281,539	288,859	296,369	304,075	311,980
Losses MW	2	2	2	2	2	2	2	2	2	2
Losses MWh	9,990	10,361	10,672	10,994	11,333	11,668	12,012	12,365	12,731	13,115
Reserves MW	1	1	1	1	1	2	2	2	2	2
Mt. Elbert Losses MWh	6,420	6,420	6,420	6,420	6,420	6,420	6,420	6,420	6,420	6,420
TOTAL LOAD										
MW	49,1	50,4	51,7	53,1	54,5	56,9	58,4	59,9	61,5	63,1
MWh	264,039	270,848	277,765	284,865	292,157	299,627	307,291	315,154	323,226	331,515
SURPLUS :										
MW	0.9	0.6	0.3	0.9	0.5	7.1	4.6	4.1	1.5	1.9
MWh	6,998	10,150	11,902	10,978	11,930	67,734	101,548	87,170	71,863	84,823

25 MW Dry Fork Case Prepared Nov 2005

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
EXPENSES										
Generation Costs										
LRS mills/kWh	17.00	17.17	17.34	17.52	17.69	17.87	18.05	18.23	18.41	18.59
LRS Production Costs	\$ 3,241,034	\$ 2,896,428	\$ 2,811,936	\$ 3,176,051	\$ 2,867,989	\$ 2,983,953	\$ 3,100,478	\$ 3,012,742	\$ 2,910,571	\$ 3,339,627
Dry Fork mills/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Dry Fork Cost	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
CUS Tariff Rate	\$ 1.46	\$ 1.39	\$ 1.32	\$ 2.07	\$ 1.81	\$ 1.78	\$ 1.73	\$ 1.70	\$ 1.67	\$ 1.63
Months										
CUS Wheeling										
* Wheeling	\$ 648,637	\$ 697,683	\$ 750,438	\$ 807,181	\$ 862,582	\$ 911,500	\$ 919,000	\$ 1,032,664	\$ 1,124,914	\$ 1,202,124
Facilities Charge	\$ 8,352	\$ 8,603	\$ 8,603	\$ 8,603	\$ 8,603	\$ 8,603	\$ 8,603	\$ 8,603	\$ 8,603	\$ 8,603
RMRG	\$ 18,000	\$ 18,540	\$ 19,096	\$ 19,669	\$ 20,259	\$ 20,867	\$ 21,493	\$ 22,138	\$ 22,802	\$ 23,486
Regional Coordination	\$ 6,000	\$ 6,180	\$ 6,365	\$ 6,556	\$ 6,753	\$ 6,956	\$ 7,164	\$ 7,379	\$ 7,601	\$ 7,829
WAPA Services	\$ 30,000	\$ 30,900	\$ 31,827	\$ 32,782	\$ 33,765	\$ 34,778	\$ 35,822	\$ 36,896	\$ 38,003	\$ 39,143
Regulation	\$ 33,530	\$ 36,696	\$ 40,160	\$ 43,952	\$ 47,389	\$ 51,116	\$ 55,124	\$ 59,447	\$ 64,109	\$ 69,356
Trans. Maintenance	\$ 6,000	\$ 6,180	\$ 6,365	\$ 6,556	\$ 6,753	\$ 6,956	\$ 7,164	\$ 7,379	\$ 7,601	\$ 7,829
Total Generation Costs	\$ 3,991,553	\$ 3,701,211	\$ 3,674,792	\$ 4,101,353	\$ 3,854,105	\$ 8,712,124	\$ 12,260,376	\$ 12,312,926	\$ 12,356,838	\$ 12,935,127
Purchased Power										
Spot Market mills/kWh										
* Spot Market Purchase	\$ 799,901.93	\$ 1,000,935.00	\$ 1,153,615.45	\$ 694,550.01	\$ 3,996,194.35	\$ 2,950,871.04	\$ -	\$ -	\$ 2,558,14	\$ 164,68
I.AP & SCLIP Support mills/kWh	\$ 71.21	\$ 65.00	\$ 66.95	\$ 68.96	\$ 71.03	\$ 73.16	\$ 75.35	\$ 77.61	\$ 79.94	\$ 82,34
Contract Purchases mills/kWh	\$ 42.50	\$ 42.50	\$ 42.50	\$ 42.50	\$ 42.50	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00
Reserve Purchase	\$ 74,424.00	\$ 76,656.72	\$ 78,956.42	\$ 81,325.11	\$ 83,764.87	\$ 172,555.63	\$ 177,732.30	\$ 183,064.27	\$ 188,556.19	\$ 194,212.88
Contract Purchases	\$ 1,151,580.00	\$ 1,976,760.00	\$ 2,528,580.00	\$ 2,266,440.00	\$ 1,480,020.00	\$ -	\$ -	\$ -	\$ -	\$ -
I.AP mills/KWh										
I.AP	\$ 890,811.00	\$ 896,597.10	\$ 923,495.01	\$ 948,763.67	\$ 970,008.51	\$ 999,108.77	\$ 1,029,082.03	\$ 1,059,954.49	\$ 1,088,928.91	\$ 1,113,264.97
LAP Support	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0
SCLIP mills/kWh	\$ 26.50	\$ 27.83	\$ 28.66	\$ 29.52	\$ 30.41	\$ 31.32	\$ 32.26	\$ 33.22	\$ 34.22	\$ 35.25
SLCIP	\$ 479,069.00	\$ 522,275.25	\$ 549,264.11	\$ 577,579.37	\$ 594,906.75	\$ 612,733.95	\$ 631,136.57	\$ 650,070.67	\$ 669,572.79	\$ 689,659.97
Total Purchases	\$ 3,395,785.93	\$ 4,473,224.07	\$ 5,233,910.99	\$ 4,568,658.16	\$ 7,124,894.48	\$ 4,735,289.38	\$ 1,837,950.90	\$ 1,893,089.43	\$ 1,949,616.02	\$ 1,997,302.50
TOTAL POWER COSTS	\$ 7,387,338.93	\$ 8,174,434.69	\$ 8,908,702.71	\$ 8,670,010.92	\$ 10,978,999.59	\$ 13,447,412.94	\$ 14,098,326.60	\$ 14,206,015.77	\$ 14,306,453.67	\$ 14,932,429.10
Miscellaneous										
Member Services	\$ 39,000.00	\$ 40,170.00	\$ 41,375.10	\$ 42,616.35	\$ 43,894.84	\$ 45,211.69	\$ 46,568.04	\$ 47,965.08	\$ 49,404.03	\$ 50,886.15
A&G	\$ 642,429.00	\$ 661,701.87	\$ 681,552.93	\$ 701,999.51	\$ 723,059.50	\$ 744,751.28	\$ 767,093.82	\$ 790,106.64	\$ 813,809.84	\$ 838,224.13
Outside Services	\$ 85,700.00	\$ 88,200.00	\$ 90,700.00	\$ 93,200.00	\$ 95,700.00	\$ 98,200.00	\$ 100,700.00	\$ 103,200.00	\$ 105,700.00	\$ 108,200.00
Depreciation	\$ 640,235.00	\$ 645,235.00	\$ 650,235.00	\$ 655,235.00	\$ 660,235.00	\$ 665,235.00	\$ 670,235.00	\$ 675,235.00	\$ 680,235.00	\$ 685,235.00
Depreciation Dry Fork	\$ 1,407,364.00	\$ 1,435,306.87	\$ 1,463,863.03	\$ 1,493,050.87	\$ 1,522,889.34	\$ 3,297,997.97	\$ 3,329,196.86	\$ 3,361,106.72	\$ 3,393,748.87	\$ 3,427,145.29
TOTAL MIS.										
TOTAL OPERATING EXPENSES	\$ 8,794,702.93	\$ 9,609,741.56	\$ 10,372,565.73	\$ 10,163,061.79	\$ 12,501,888.93	\$ 16,745,410.91	\$ 17,427,523.46	\$ 17,567,122.49	\$ 17,700,202.54	\$ 18,359,574.39

25 MW Dry Fork Case Prepared Nov 2005

	2016	2007	2008	2009	2010	2011	2012	2013	2014	2015
Financing Costs										
LRS Debt Service - Interest	\$ 585,160.00	\$ 545,050.00	\$ 492,550.00	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
LRS Debt Service - Principal	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Unamortized Debt Expense	\$ 339,233.00	\$ 339,233.00	\$ 339,233.00	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
DF Debt Service - Interest	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
DF Debt Service - Principal	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Unamortized Debt Expense	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Financing Costs	\$ 924,393.00	\$ 884,283.00	\$ 831,783.00	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Costs	\$ 9,719,095.93	\$ 10,494,024.56	\$ 11,204,348.73	\$ 10,163,061.79	\$ 12,501,888.93	\$ 16,745,410.91	\$ 17,427,523.46	\$ 17,567,122.49	\$ 17,700,202.54	\$ 18,359,574.39
REVENUES										
Member Sales	\$ 8,847,258.47	\$ 9,563,583.71	\$ 10,207,531.12	\$ 9,482,844.50	\$ 11,751,083.83	\$ 13,451,643.62	\$ 12,380,119.99	\$ 12,967,048.49	\$ 13,626,025.39	\$ 13,416,094.11
RMGC (surplus) Sales	\$ 314,912.46	\$ 405,996.85	\$ 490,373.62	\$ 465,877.29	\$ 521,465.10	\$ 3,049,427.29	\$ 4,708,896.47	\$ 4,163,433.00	\$ 3,535,277.15	\$ 4,298,031.28
Interest Income	\$ 556,925.00	\$ 524,444.00	\$ 506,444.00	\$ 214,340.00	\$ 229,340.00	\$ 244,340.00	\$ 338,507.00	\$ 436,641.00	\$ 538,900.00	\$ 645,449.00
TOTAL REVENUES	\$ 9,719,095.93	\$ 10,494,024.56	\$ 11,204,348.73	\$ 10,163,061.79	\$ 12,501,888.93	\$ 16,745,410.91	\$ 17,427,523.46	\$ 17,567,122.49	\$ 17,700,202.54	\$ 18,359,574.39
ROCKY MTN GENERATION COOP										
RMGC mills/kWh (Sales)	45.00	40.00	41.20	42.44	43.71	45.02	46.37	47.76	49.19	50.67
Surplus available MW	0.9	0.6	0.3	0.9	0.5	7.1	4.6	4.1	1.5	1.9
MWh	6,998	10,150	11,902	10,978	11,930	67,734	101,548	87,170	71,863	84,823

Nineteen

The inflation rate was assumed to be 3%.

The load growth rate was assumed to be 2.6%

loads and resources were evaluated in July as that month was to be the first full month of the new system.

that IRS costs are based on the 2005 data.

The LRC costs are based on the latest estimates from Basin through 2015. The growth rate between 2006 and 2015 was straight lined into the future.

LAP power costs were provided by WAPA based on the latest rate and their projection through 2015. Then, these were projected into the future.

The plant factor for LRS is 90% with the exception of planned maintenance which is modeled according to the outage schedule.

Due to hydrology, SCLIP rates are unknown at this point but 2005 is based on our best estimate.

25 MW Dry Fork Case Prepared Nov 2005

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
RESOURCES:										
These are based on the July loads and resources.										
Normal LRS MW	22	23	22	23	22	23	22	23	22	23
MW/h	158,110	165,296	171,811	165,296	158,110	179,621	158,110	165,296	171,811	165,296
Emergency LRS MW	1	1	1	1	1	1	1	1	1	1
Dry Fork MW	25	25	25	25	25	25	25	25	25	25
MW/h	186,150	186,150	186,150	186,150	186,150	186,150	186,150	186,150	186,150	186,150
PS-LAP MW	12	12	12	12	12	12	12	12	12	12
MW/h	30,999	30,999	30,999	30,999	30,999	30,999	30,999	30,999	30,999	30,999
LAP Support MW	0	0	0	0	0	0	0	0	0	0
SI CIP MW	3	3	3	3	3	3	3	3	3	3
SCLIP MW	19,566	19,566	19,566	19,566	19,566	19,566	19,566	19,566	19,566	19,566
SCLIP Off Peak Replacement MW	0	0	0	0	0	0	0	0	0	0
WRP (total 5,036 kW SCLIP) MW	0	0	0	0	0	0	0	0	0	0
WRP Energy (MW/h)	0	0	0	0	0	0	0	0	0	0
Actual AHP Energy										
Contracted Purchases MW	0	0	0	0	0	0	0	0	0	0
MW/h	0	0	0	0	0	0	0	0	0	0
Spot Market MW	2	3	6	6	9	10	13	14	17	18
MW/h	196	246	346	2,632	5,249	1,359	13,222	16,237	21,028	36,425
TOTAL RESOURCES	MW	65	67	69	70	72	74	76	78	80
	MW/h	395,021	402,257	408,872	404,643	400,074	417,695	408,047	418,248	429,554
LOAD:										
MW	60	62	64	65	67	69	71	72	74	76
MW/h	320,092	328,414	336,953	345,714	354,702	363,925	373,387	383,095	393,055	403,275
Losses MW	2	2	3	3	3	3	3	3	3	3
Losses MW	13,496	13,887	14,289	14,700	15,123	15,556	16,001	16,457	16,926	17,437
Reserves MW	2	2	2	2	2	2	2	2	2	2
Mt. Elbert Losses MW	6,420	6,420	6,420	6,420	6,420	6,420	6,420	6,420	6,420	6,420
TOTAL LOAD	MW	64.7	66.4	68.1	69.9	71.7	73.5	75.4	77.4	79.4
	MW/h	340,008	348,722	357,662	366,834	376,245	385,901	393,808	405,972	416,401
SURPLUS :										
MW	0.3	0.6	0.9	0.1	0.3	0.5	0.6	0.6	0.6	0.5
MW/h	55,013	53,536	51,211	37,809	23,828	31,794	12,239	12,276	13,153	11,305

25 MW Dry Fork Case Prepared Nov 2005

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
EXPENSES										
Generation Costs										
LRS Production Costs	\$ 2,969,073	\$ 3,135,071	\$ 3,291,220	\$ 3,198,086	\$ 3,089,629	\$ 3,545,081	\$ 3,151,731	\$ 3,327,941	\$ 3,493,696	\$ 3,394,833
Dry Fork mills/kWh										
Total Dry Fork Cost	\$ 1.63	\$ 1.63	\$ 1.63	\$ 1.63	\$ 1.63	\$ 1.63	\$ 1.63	\$ 1.63	\$ 1.63	\$ 1.63
CUS Tariff Rate	\$ 12	\$ 12	\$ 12	\$ 12	\$ 12	\$ 12	\$ 12	\$ 12	\$ 12	\$ 12
Months										
CUS Wheeling	\$ 489,000	\$ 489,000	\$ 489,000	\$ 489,000	\$ 489,000	\$ 489,000	\$ 489,000	\$ 489,000	\$ 489,000	\$ 489,000
* Wheeling	\$ 1,294,632	\$ 1,372,804	\$ 1,467,027	\$ 1,567,718	\$ 1,675,319	\$ 1,790,306	\$ 1,913,185	\$ 2,044,498	\$ 2,184,823	\$ 2,334,780
Facilities Charge	\$ 8,603	\$ 8,603	\$ 8,603	\$ 8,603	\$ 8,603	\$ 8,603	\$ 8,603	\$ 8,603	\$ 8,603	\$ 8,603
RMRG	\$ 24,190	\$ 24,916	\$ 25,664	\$ 26,434	\$ 27,227	\$ 28,043	\$ 28,885	\$ 29,751	\$ 30,644	\$ 31,563
Regional Coordination	\$ 8,063	\$ 8,305	\$ 8,555	\$ 8,811	\$ 9,076	\$ 9,348	\$ 9,628	\$ 9,917	\$ 10,215	\$ 10,521
WAPA Services	\$ 40,317	\$ 41,527	\$ 42,773	\$ 44,056	\$ 45,378	\$ 46,739	\$ 48,141	\$ 49,585	\$ 51,073	\$ 52,605
Regulation	\$ 74,558	\$ 80,405	\$ 86,710	\$ 93,510	\$ 100,843	\$ 108,751	\$ 117,279	\$ 126,476	\$ 136,394	\$ 147,090
Trans. Maintenance	\$ 8,063	\$ 8,305	\$ 8,555	\$ 8,811	\$ 9,076	\$ 9,348	\$ 9,628	\$ 9,917	\$ 10,215	\$ 10,521
Total Generation Costs	\$ 12,732,335	\$ 13,073,029	\$ 13,411,239	\$ 13,507,993	\$ 13,597,743	\$ 14,260,248	\$ 14,083,360	\$ 14,486,041	\$ 14,888,918	\$ 15,038,515
Purchased Power										
Spot Market mills/kWh	\$ 84.81	\$ 87.35	\$ 89.98	\$ 92.67	\$ 95.45	\$ 98.32	\$ 101.27	\$ 104.31	\$ 107.44	\$ 110.66
* Spot Market Purchase	\$ 16,622.81	\$ 21,489.22	\$ 31,131.42	\$ 24,3919.17	\$ 501,041.68	\$ 133,614.61	\$ 1,338,963.94	\$ 1,693,615.20	\$ 2,259,145.20	\$ 4,030,723.08
I.AP & SCLIP Support mills/kWh	\$ 84.81	\$ 87.35	\$ 89.98	\$ 92.67	\$ 95.45	\$ 98.32	\$ 101.27	\$ 104.31	\$ 107.44	\$ 110.66
Contract Purchases mills/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Reserve Purchase	\$ 200,039.27	\$ 206,040.44	\$ 212,221.66	\$ 218,588.31	\$ 225,145.96	\$ 231,900.33	\$ 238,857.34	\$ 246,023.06	\$ 253,403.76	\$ 261,005.87
Contract Purchases	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
LAP mills/kWh	\$ 36.99	\$ 38.10	\$ 39.24	\$ 40.42	\$ 41.63	\$ 42.88	\$ 44.17	\$ 45.49	\$ 46.86	\$ 48.26
LAP	\$ 1,146,662.92	\$ 1,181,062.81	\$ 1,216,494.69	\$ 1,252,989.54	\$ 1,290,579.22	\$ 1,329,296.60	\$ 1,369,175.50	\$ 1,410,250.76	\$ 1,452,558.28	\$ 1,496,135.03
LAP Support	\$ 50	\$ 50	\$ 50	\$ 50	\$ 50	\$ 50	\$ 50	\$ 50	\$ 50	\$ 50
SCLIP mills/kWh	\$ 36.31	\$ 37.39	\$ 38.52	\$ 39.67	\$ 40.86	\$ 42.09	\$ 43.35	\$ 44.65	\$ 45.99	\$ 47.37
SCLIP	\$ 710,349.77	\$ 731,660.26	\$ 753,610.07	\$ 776,218.37	\$ 799,504.92	\$ 823,490.07	\$ 848,194.77	\$ 873,640.62	\$ 899,849.84	\$ 926,845.33
Total Purchases	\$ 2,073,674.77	\$ 2,140,252.74	\$ 2,213,457.84	\$ 2,491,715.39	\$ 2,816,271.78	\$ 2,518,301.62	\$ 3,795,191.55	\$ 4,223,529.64	\$ 4,864,957.08	\$ 6,714,709.31
TOTAL POWER COSTS	\$ 14,806,010.14	\$ 15,213,282.00	\$ 15,624,696.57	\$ 15,999,708.44	\$ 16,414,015.27	\$ 16,778,549.84	\$ 17,878,551.43	\$ 18,709,570.82	\$ 19,753,875.15	\$ 21,753,223.99
Miscellaneous										
Member Services	\$ 52,412.74	\$ 53,985.12	\$ 55,604.67	\$ 57,272.81	\$ 58,991.00	\$ 60,760.73	\$ 62,583.55	\$ 64,461.06	\$ 66,394.89	\$ 68,386.74
A&G	\$ 863,370.86	\$ 889,271.98	\$ 915,950.14	\$ 943,428.64	\$ 971,731.50	\$ 1,000,883.45	\$ 1,030,909.95	\$ 1,061,837.25	\$ 1,093,692.37	\$ 1,126,503.14
Outside services	\$ 110,700.00	\$ 113,200.00	\$ 115,700.00	\$ 118,200.00	\$ 120,700.00	\$ 123,200.00	\$ 125,700.00	\$ 128,200.00	\$ 130,700.00	\$ 133,200.00
Depreciation	\$ 150,000.00	\$ 155,000.00	\$ 160,000.00	\$ 165,000.00	\$ 170,000.00	\$ 175,000.00	\$ 180,000.00	\$ 185,000.00	\$ 190,000.00	\$ 195,000.00
Depreciation Dry Fork	\$ 1,744,600.00	\$ 1,744,600.00	\$ 1,744,600.00	\$ 1,744,600.00	\$ 1,744,600.00	\$ 1,744,600.00	\$ 1,744,600.00	\$ 1,744,600.00	\$ 1,744,600.00	\$ 1,744,600.00
TOTAL MISC.	\$ 2,921,083.59	\$ 2,956,057.10	\$ 2,991,854.82	\$ 3,028,501.46	\$ 3,066,022.50	\$ 3,104,444.18	\$ 3,143,793.50	\$ 3,184,098.31	\$ 3,225,387.26	\$ 3,267,689.88
TOTAL OPERATING EXPENSES	\$ 17,727,093.73	\$ 18,169,339.10	\$ 18,616,551.38	\$ 19,028,209.90	\$ 19,480,037.78	\$ 19,882,994.02	\$ 21,022,344.93	\$ 21,893,669.13	\$ 22,979,262.41	\$ 25,020,913.87

25 MW Dry Fork Case Prepared Nov 2005

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Financing Costs										
I.R.S. Debt Service - Interest	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
I.R.S. Debt Service - Principal	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Unamortized Debt Expense	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
DF Debt Service - Interest	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
DF Debt Service - Principal	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Unamortized Debt Expense	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Total Financing Costs	\$ 17,727,093.73	\$ 18,169,339.10	\$ 18,616,551.38	\$ 19,028,209.90	\$ 19,480,037.78	\$ 19,882,994.02	\$ 21,022,344.93	\$ 21,893,669.13	\$ 22,979,262.41	\$ 25,020,913.87
REVENUES										
Member Sales	\$ 14,099,471.64	\$ 14,440,927.17	\$ 14,832,550.63	\$ 15,821,306.94	\$ 16,923,292.72	\$ 16,691,453.87	\$ 18,876,238.24	\$ 19,601,959.68	\$ 20,480,589.10	\$ 22,491,464.18
RMGC (surplus) Sales	\$ 2,871,162.09	\$ 2,877,909.93	\$ 2,835,494.76	\$ 2,156,272.96	\$ 1,399,706.06	\$ 1,923,335.15	\$ 762,701.69	\$ 787,984.45	\$ 869,615.32	\$ 769,845.69
Interest Income	\$ 756,460.00	\$ 850,502.00	\$ 948,506.00	\$ 1,050,630.00	\$ 1,157,039.00	\$ 1,267,905.00	\$ 1,383,405.00	\$ 1,503,725.00	\$ 1,629,058.00	\$ 1,759,604.00
TOTAL REVENUES	\$ 17,727,093.73	\$ 18,169,339.10	\$ 18,616,551.38	\$ 19,028,209.90	\$ 19,480,037.78	\$ 19,882,994.02	\$ 21,022,344.93	\$ 21,893,669.13	\$ 22,979,262.41	\$ 25,020,913.87
MILLS PER KWh	44.05	43.97	44.02	45.76	47.71	45.87	50.55	51.17	52.11	55.77
ROCKY MTN GENERATION COOP										
RMGC mills/kWh (Sales)	52.19	53.76	55.37	57.03	58.74	60.50	62.32	64.19	66.11	68.10
Surplus available MW MWh	0.3 55.013	0.6 53.536	0.9 51.211	0.1 37.809	0.3 23.828	0.5 31.794	0.6 12,239	0.6 12,276	0.6 13,153	0.5 11,305
	9,088,645	8,865,477	8,672,285	8,809,896	8,974,783	8,440,318	9,079,793	8,979,884	8,935,613	9,345,668

Wyoming Municipal Power Agency

Resource Plan Review

Tim Corrigan
Jean Agras
Bahman Daryanian

April 23, 2007



Disclaimer

This presentation outlines results and principal assumptions used in analyses conducted for WMPA in May 2006 and April 2007. In conducting our analyses, we made certain assumptions with respect to future conditions and events which we believe were reasonable at that time for the purposes of this study. However, it should be anticipated that some future conditions may vary significantly from those assumed due to unanticipated events and circumstances, causing results to vary from those projected. We offer no assurances to parties other than WMPA with respect to any results shown herein.

Introduction

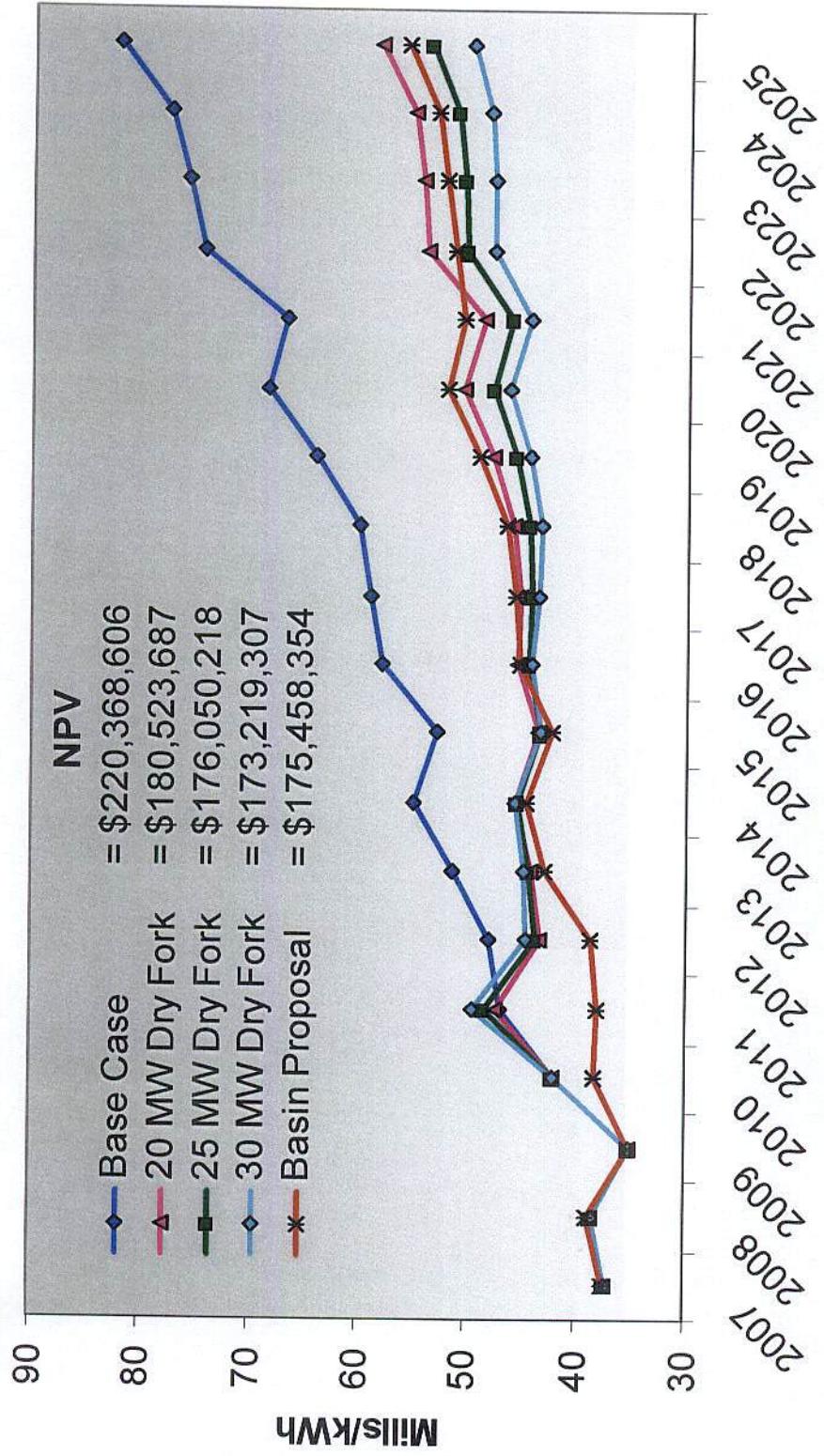
- This presentation is an update to the May 2006 R. W. Beck study of cost comparisons of selected supply options for WMPA. The supply options considered covers various levels of ownership participation in the Dry Fork Station, membership in Basin Electric, and “doing nothing” as the alternatives.
- As the first part of this current study, R. W. Beck examined the most recent cost estimates for the Dry Fork project, and provided its findings and new cost estimates in a separate written report.
- The second part of the study, reported in this presentation, consists of incorporating the new Dry Fork capital cost estimates in the previous model to provide an update to the former study’s net present value and dollar per MWh calculations.

Summary of Findings

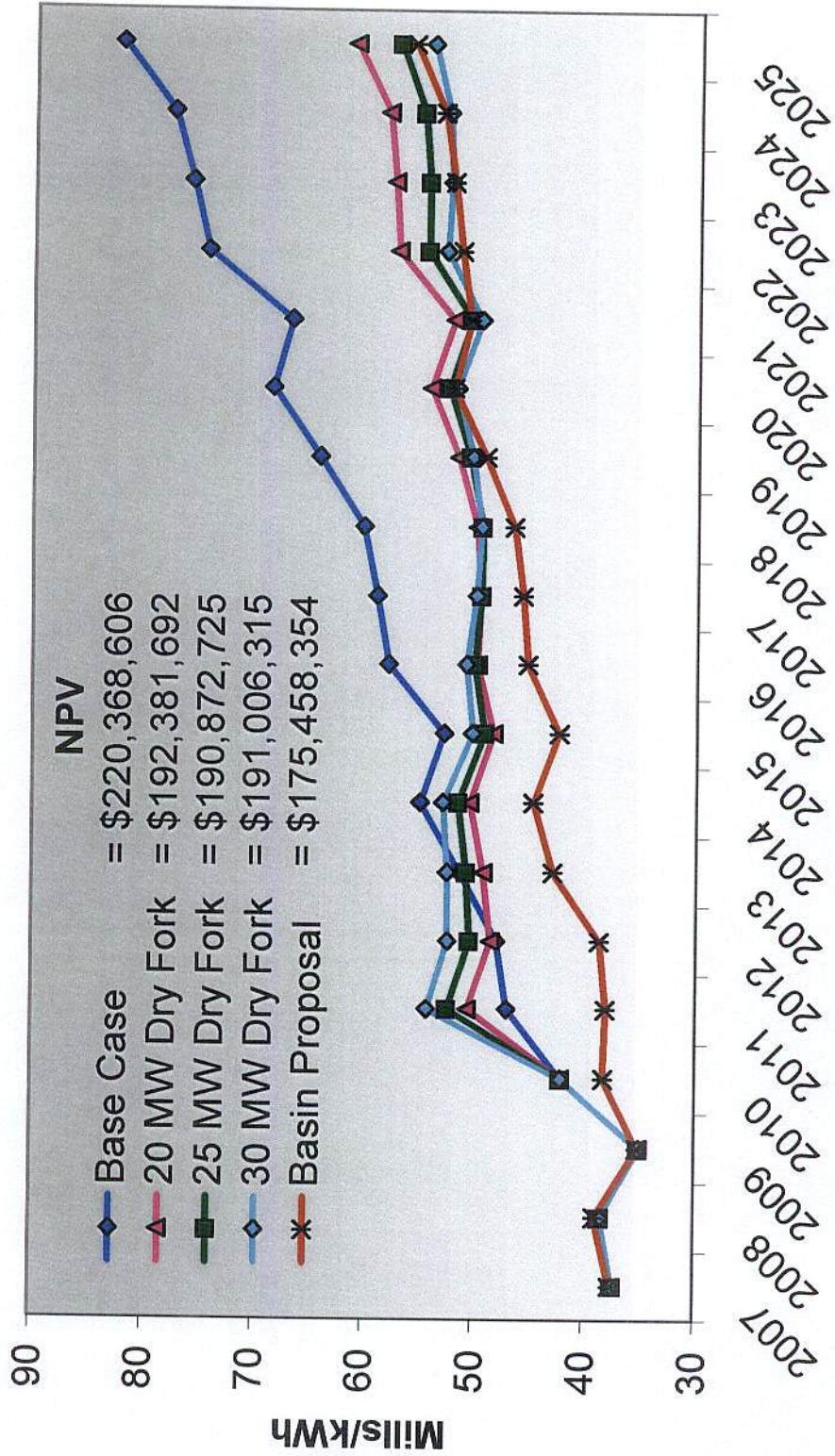
- Keeping other assumptions unchanged, the new cost estimates result in significantly higher net present value costs and \$/MWh costs under the Dry Fork scenarios, as discussed in the remainder of this presentation.
 - For instance:
 - In the Base Case, the NPV of the 20 MW Dry Fork option increased from about \$181 MM to \$192 MM
 - For the same case and option, the equivalent power costs in 2011 increased from \$47.34/MWh to \$50.54/MWh. Similarly, the equivalent power costs in 2015 increased from \$43.62/MWh to \$48.25/MWh.
 - Basin Membership was kept in the analysis to facilitate the comparison of old and new results.

Summary Base Case Results Estimated Member Rates (Analysis of May 06)

RWBECK



Summary Base Case Results Estimated Member Rates (Analysis of April 07)



Increase in NPV

Base Scenario

	May 2006	April 2007	% Change
Base Case	\$220,368,606	\$220,368,606	0.0%
20 MW Dry Fork	\$180,523,687	\$192,381,692	6.6%
25 MW Dry Fork	\$176,050,218	\$190,872,725	8.4%
30 MW Dry Fork	\$173,219,307	\$191,006,315	10.3%
Basin Proposal	\$175,458,354	\$175,458,354	0.0%

Basic Study Assumptions

- Load Growth
 - 2.6% per year
- Purchased Power Cost
 - 65 Mills/kWh
- Surplus Sales Revenue
 - Sales price of 40 Mills/kWh (used in Dry Fork Cases)
 - On-Peak price of 50 Mills/kWh and Off-Peak price of 30 Mills/kWh (used in Basin Case)
- All prices in 2007 dollars, increasing at 3% per year

Methodology for Dry Fork Cases

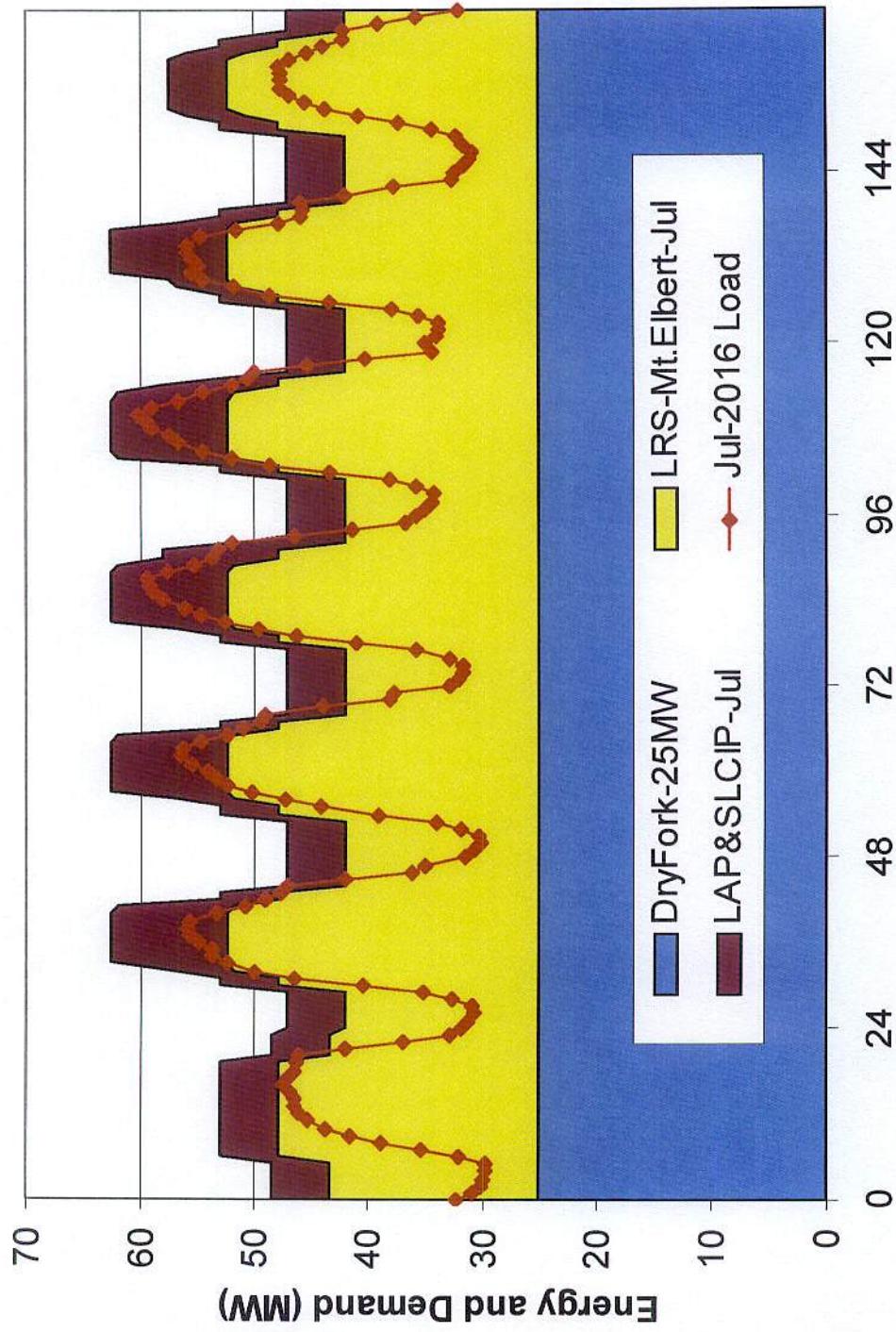
- Performed dispatch using hourly model
- Laramie River Station
 - Dispatched at full capacity when not down for maintenance or forced outage
 - Dispatched at half capacity during outage times (spring)
- Hydro Allocations (LAP & SLCIP)
 - Based on minimum and maximum takes, a typical week per month was created to get full energy

Methodology for Dry Fork Cases

- Mt. Elbert
 - Energy was consumed in the night time hours from LRS to generate additional peaking hour energy
 - Mt. Elbert was not run during months of LRS or Dry Fork outages
- Dry Fork
 - Dispatched at full capacity when not down for maintenance or outage
 - Zero capacity during outage times (fall)
 - Cost from Dry Fork Proforma

Typical Summer Week, 2016 25 MW Dry Fork Case

RW BECK



Methodology for Basin Case

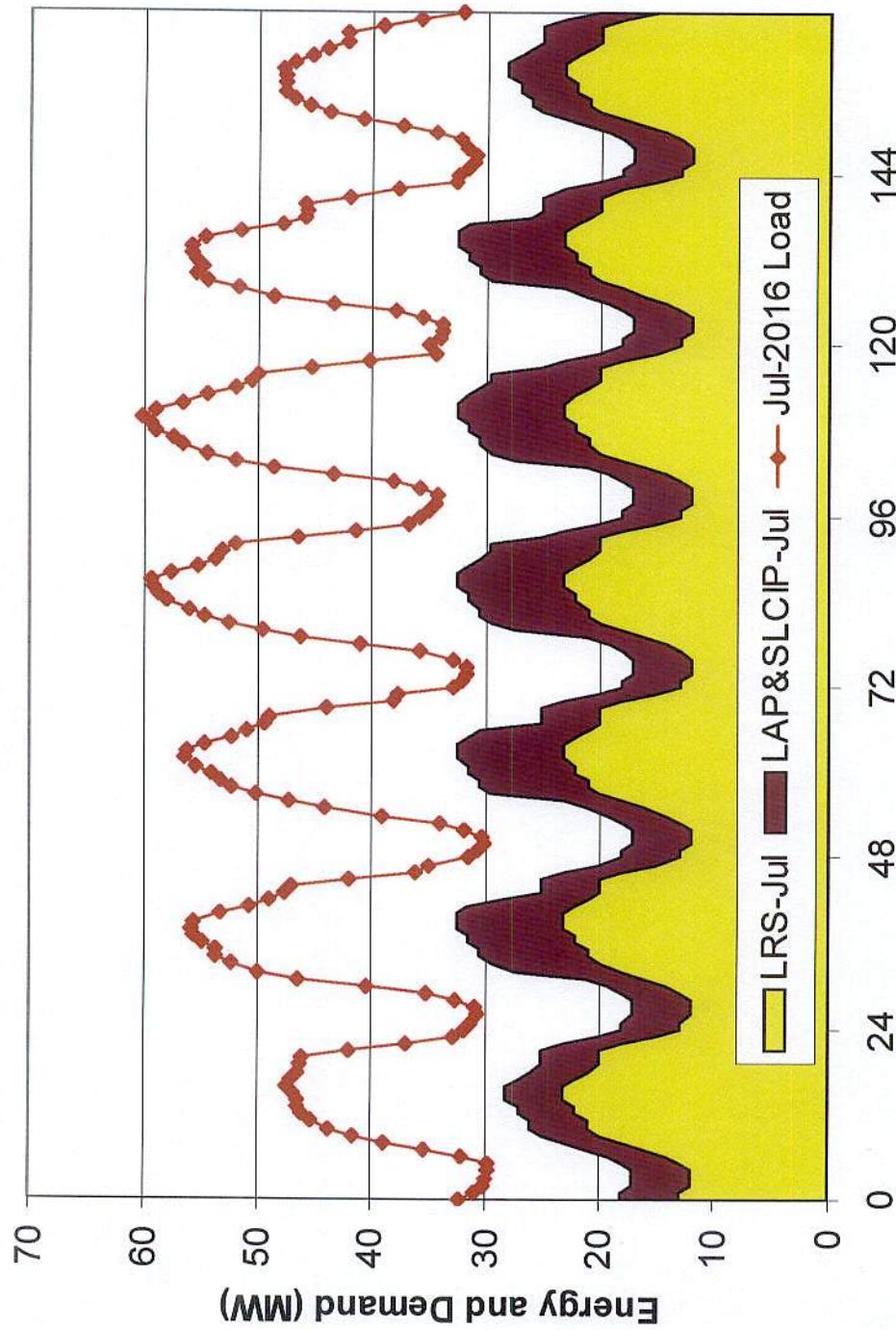
- Performed dispatch using hourly model
- Laramie River Station
 - Dispatched at allocated capacity when not down for maintenance or forced outage
 - Dispatched at half capacity or allocated capacity during outage times (spring)
- Difference between Maximum Capacity and Basin Allocation is surplus sales to Basin

Methodology for Basin Case

- Hydro Allocations (LAP & SLCIP)
 - Based on minimum and maximum takes allocated by Basin Contract, a typical week per month was created to get full energy
 - Mt. Elbert
 - Not dispatched

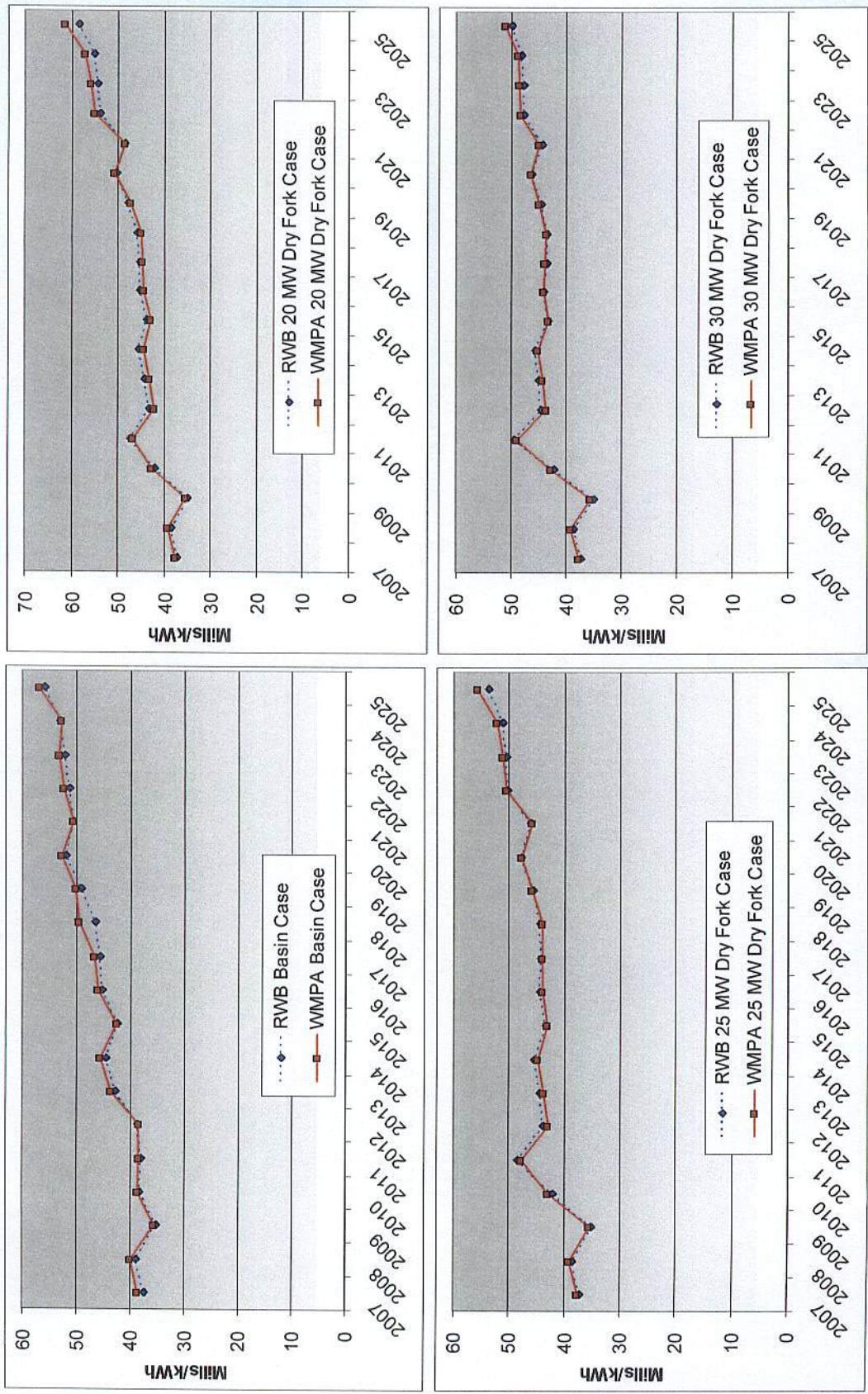
Typical Summer Week, 2016 Basin Case

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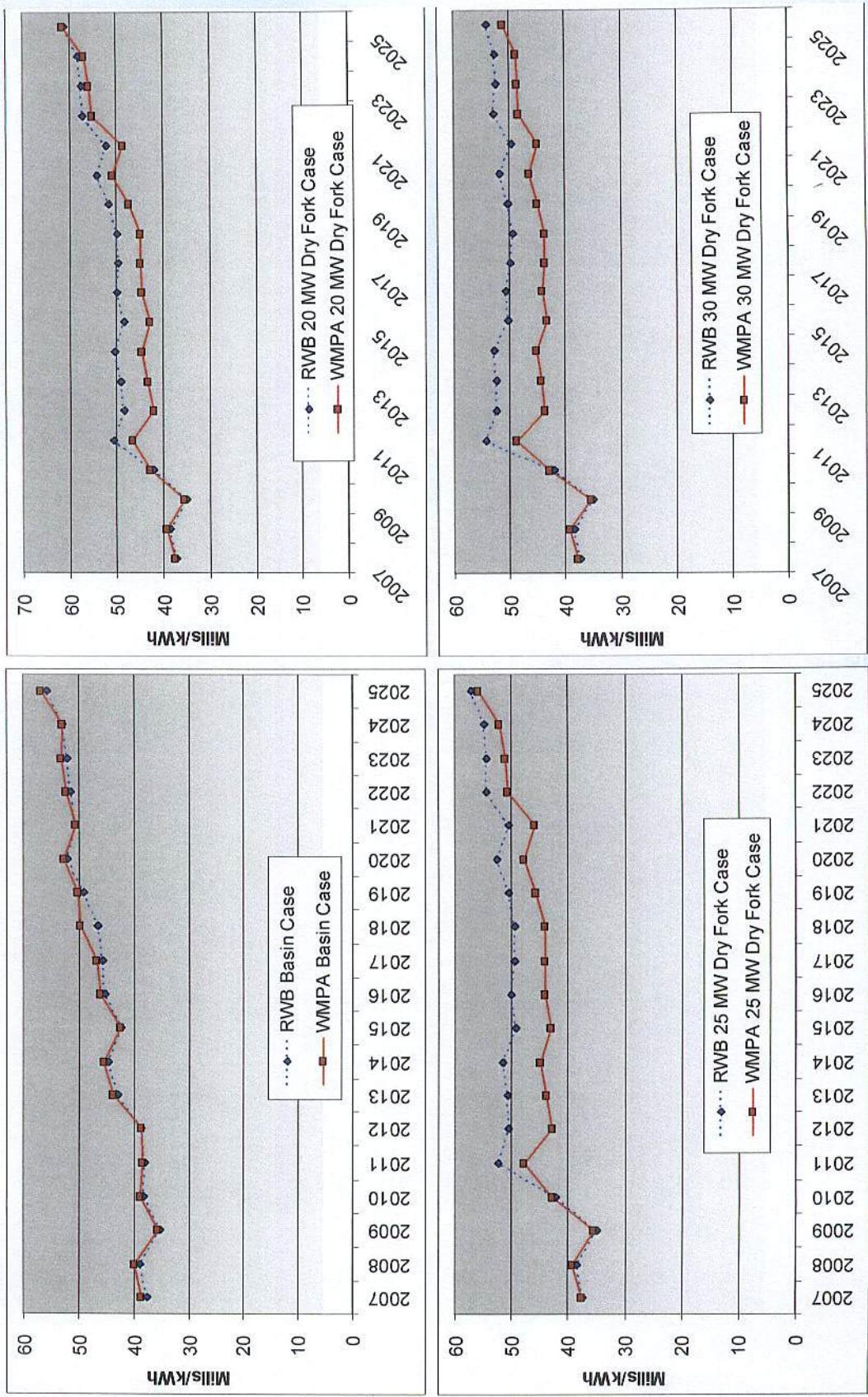


Comparison to Agency Estimates (Analysis of May 06)

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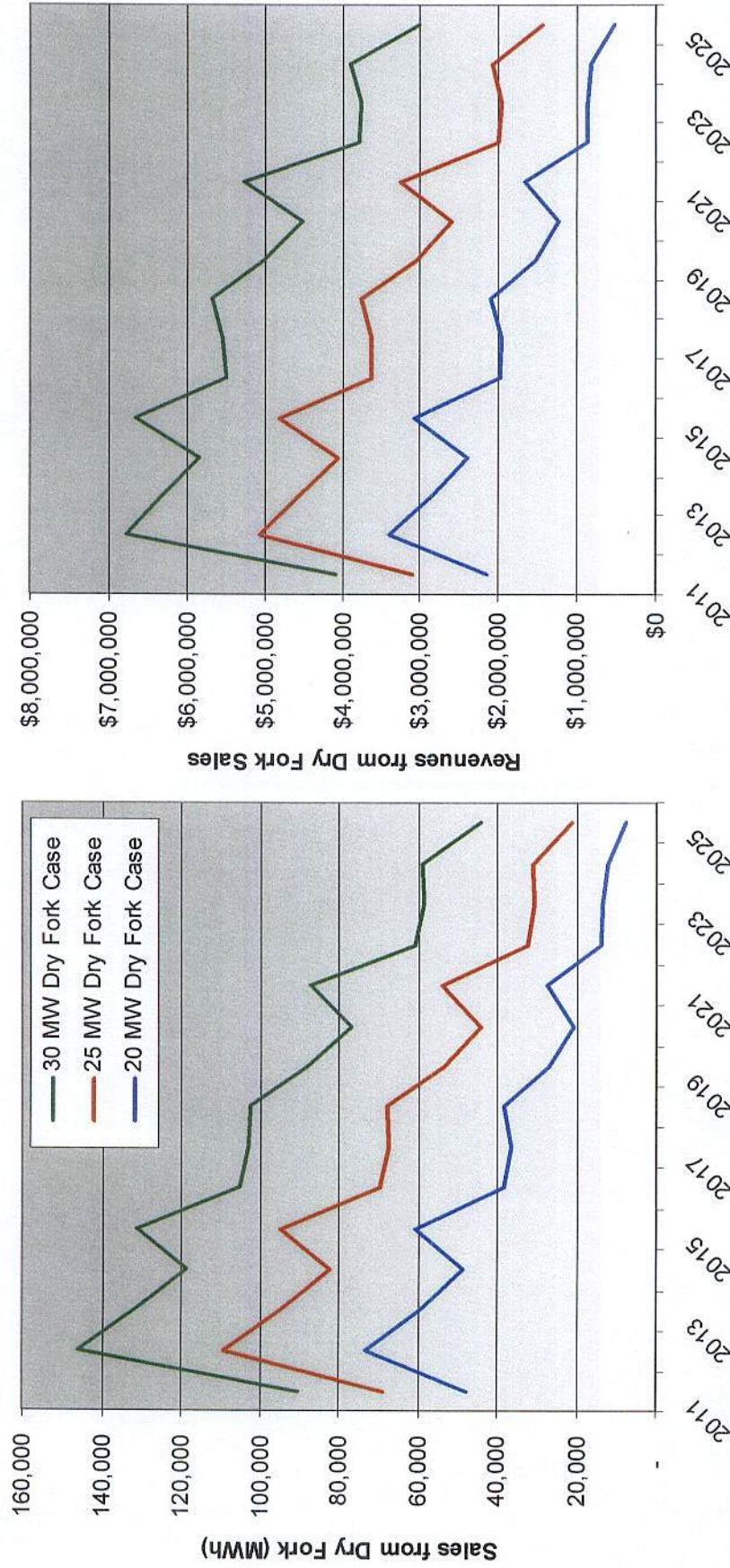
Comparison to Agency Estimates (Analysis of April 07)



Key Drivers to Results Market Sales Revenues

- The Dry Fork Cases are more sensitive to market sales than the Basin Case in the early years
- The revenues associated with sales are a key driver for maintaining lower rates
- Above 20 MW of Dry Fork, additional Dry Fork capacity primarily goes to sales

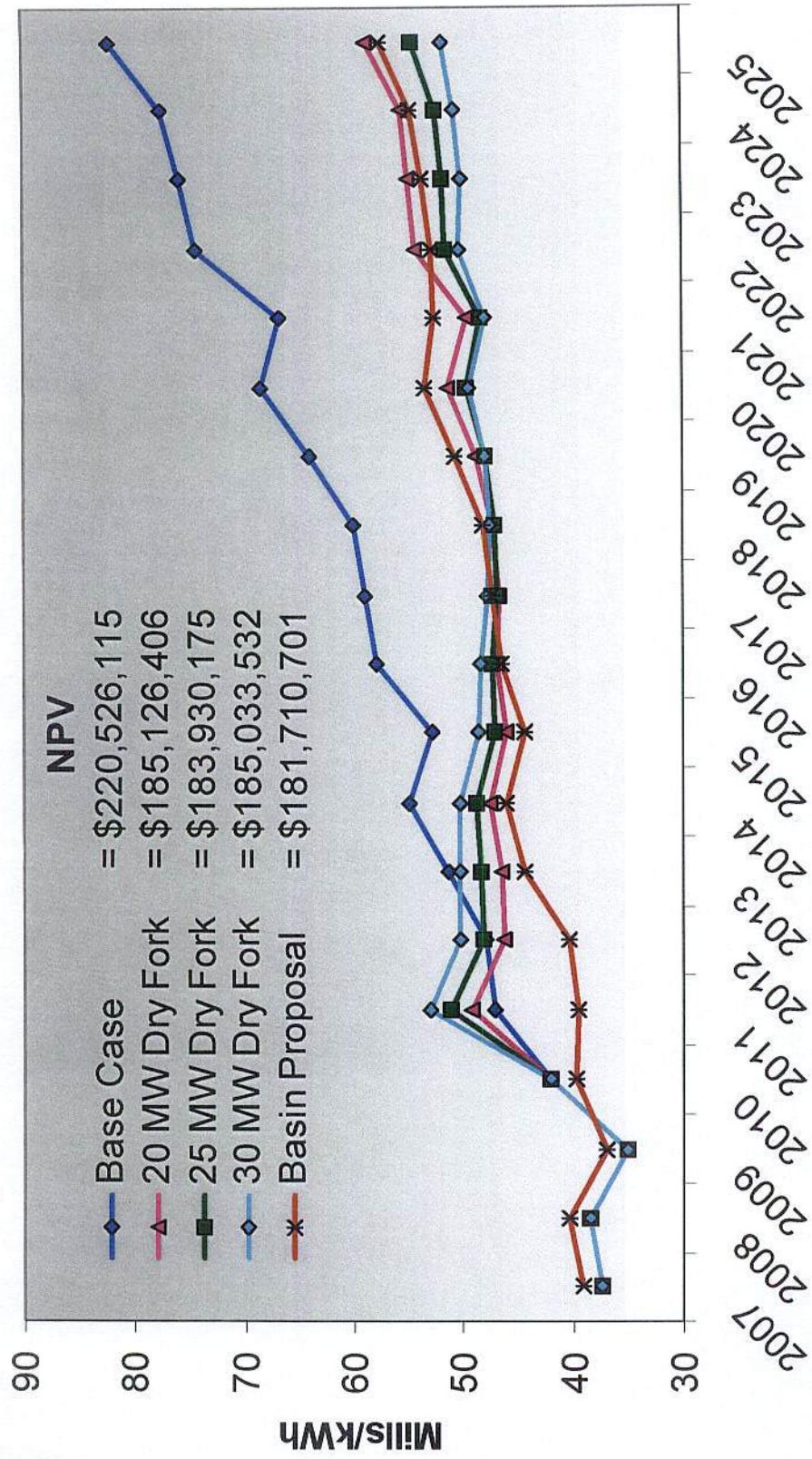
Base Case Dry Fork Sales and Sales Revenues



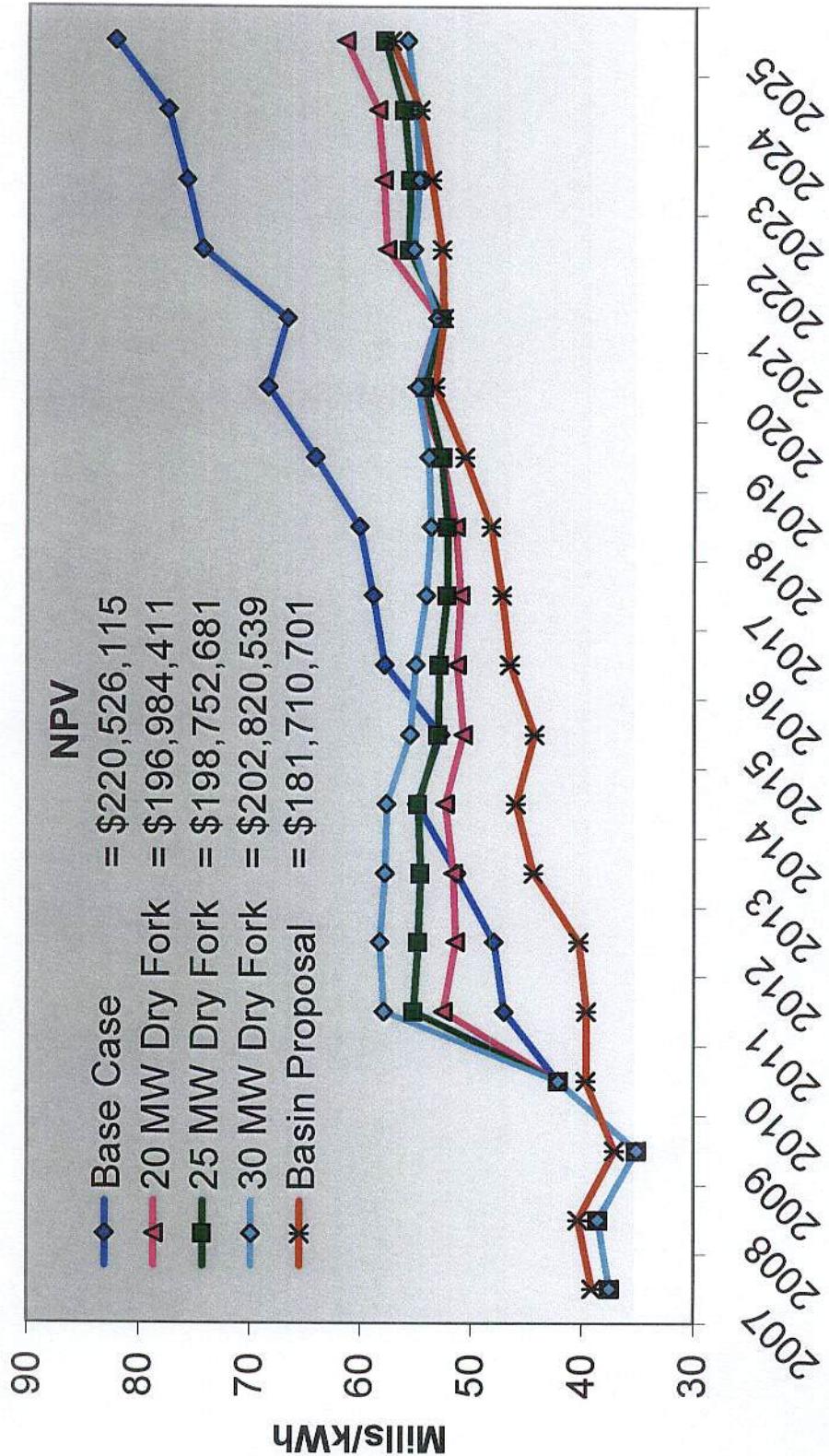
Key Drivers to Results Market Sales Revenues

- At a lower market sales price, Basin has a lower NPV
- At a 30 Mill/kWh average market price, Basin has the lowest NPV
- New higher Dry Fork capital cost estimates result in higher NPV and \$/MWh values for the Dry Fork options.

Results under Lower Sales Price (Analysis of May 06)



Results under Lower Sales Price (Analysis of April 07)



Increase in NPV

RW ECK

Low Sales Price Scenario

	May 2006	April 2007	% Change
Base Case	\$220,526,115	\$220,526,115	0.0%
20 MW Dry Fork	\$185,126,406	\$196,984,411	6.4%
25 MW Dry Fork	\$183,930,175	\$198,752,681	8.1%
30 MW Dry Fork	\$185,033,532	\$202,820,539	9.6%
Basin Proposal	\$181,710,701	\$181,710,701	0.0%

Key Drivers to Results

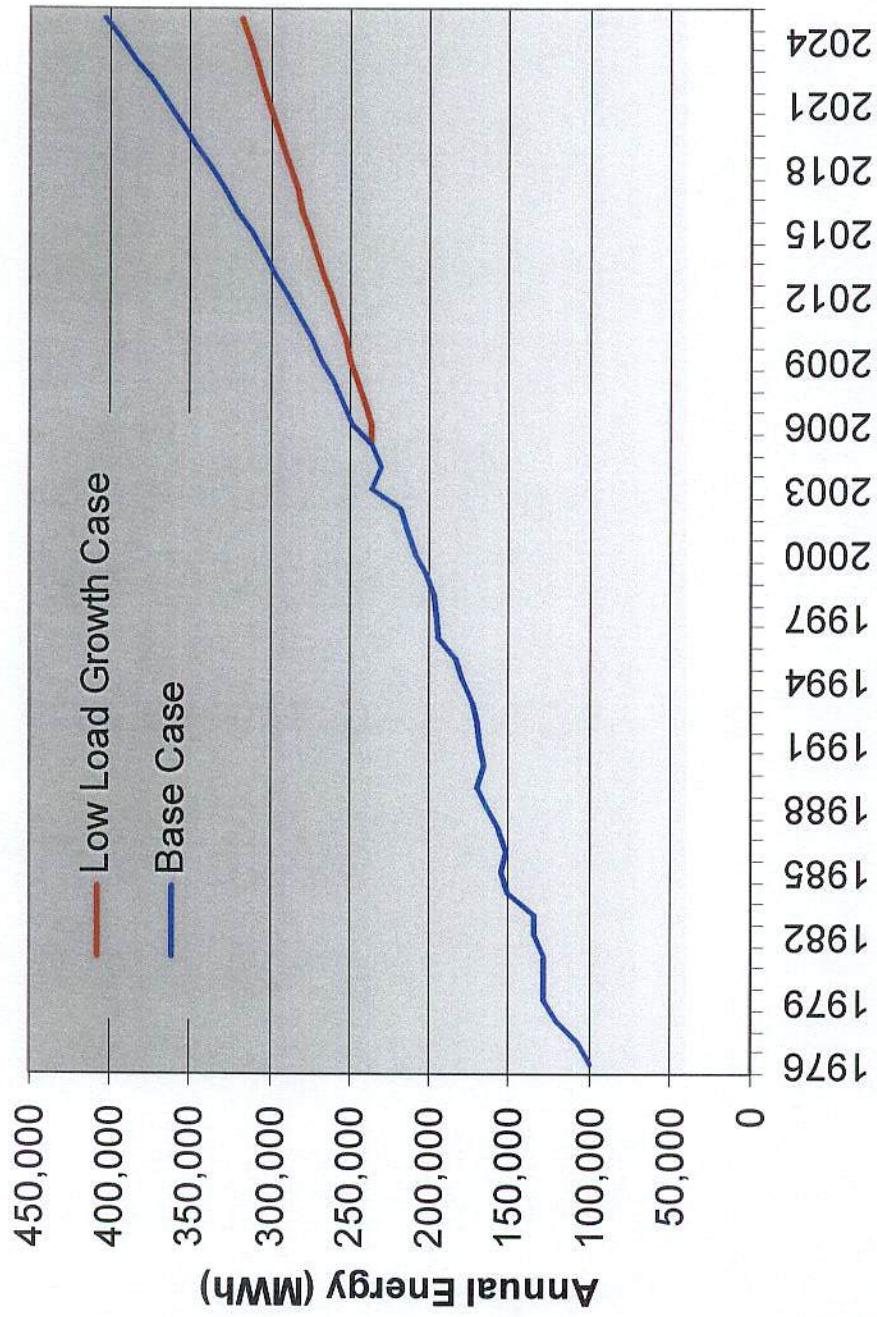
Load Forecast

RWBECK

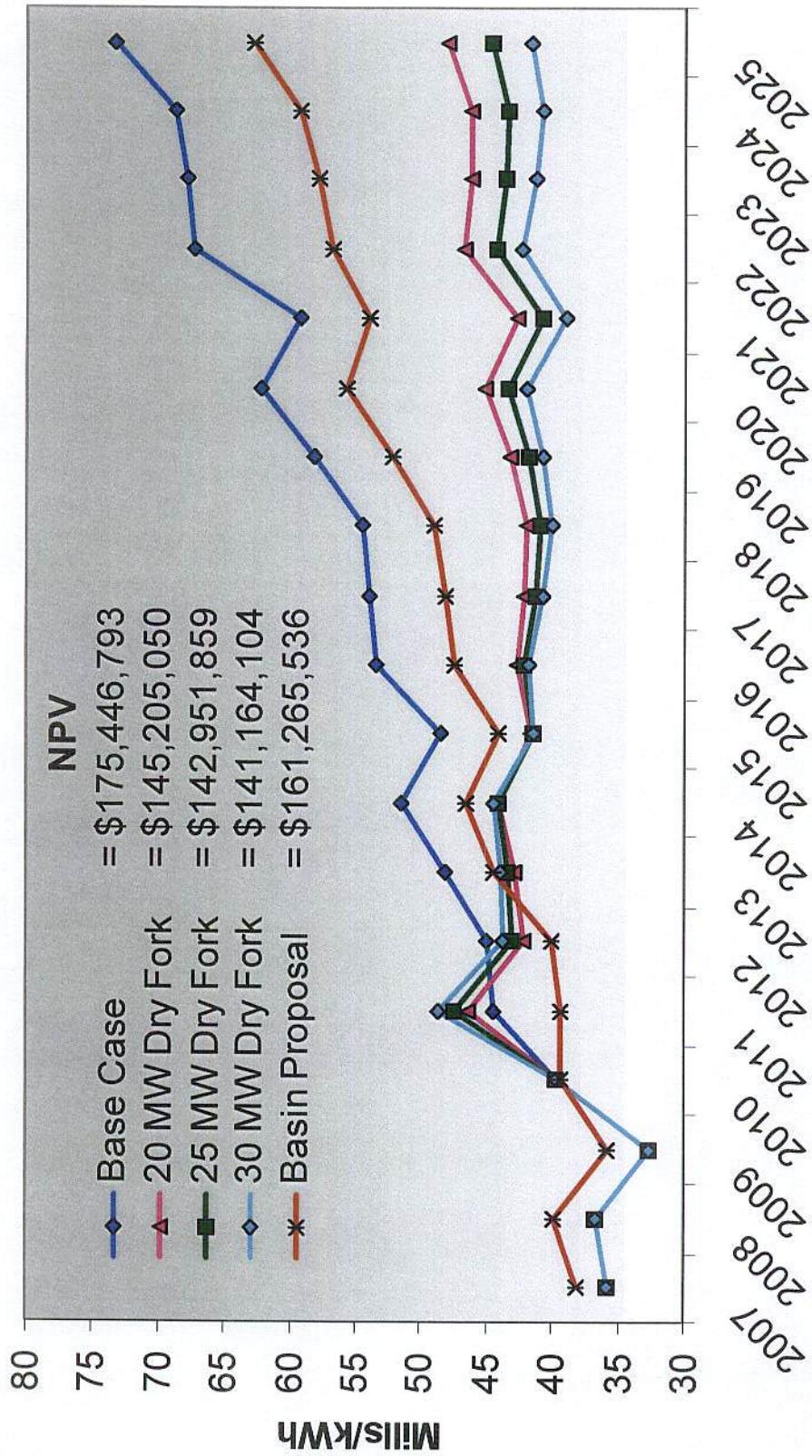
- Our Base Case model used the same load forecast used by the Agency
- If the Agency's load grows at a slower rate, the Dry Fork Cases perform significantly better than the Basin Case. However, the advantage is moderated by the new higher Dry Fork capital cost estimates.
- The reason for improved economics of Dry Fork options with lower load growth is because there are more sales into the market – greater opportunity and more risk.

Load Forecast

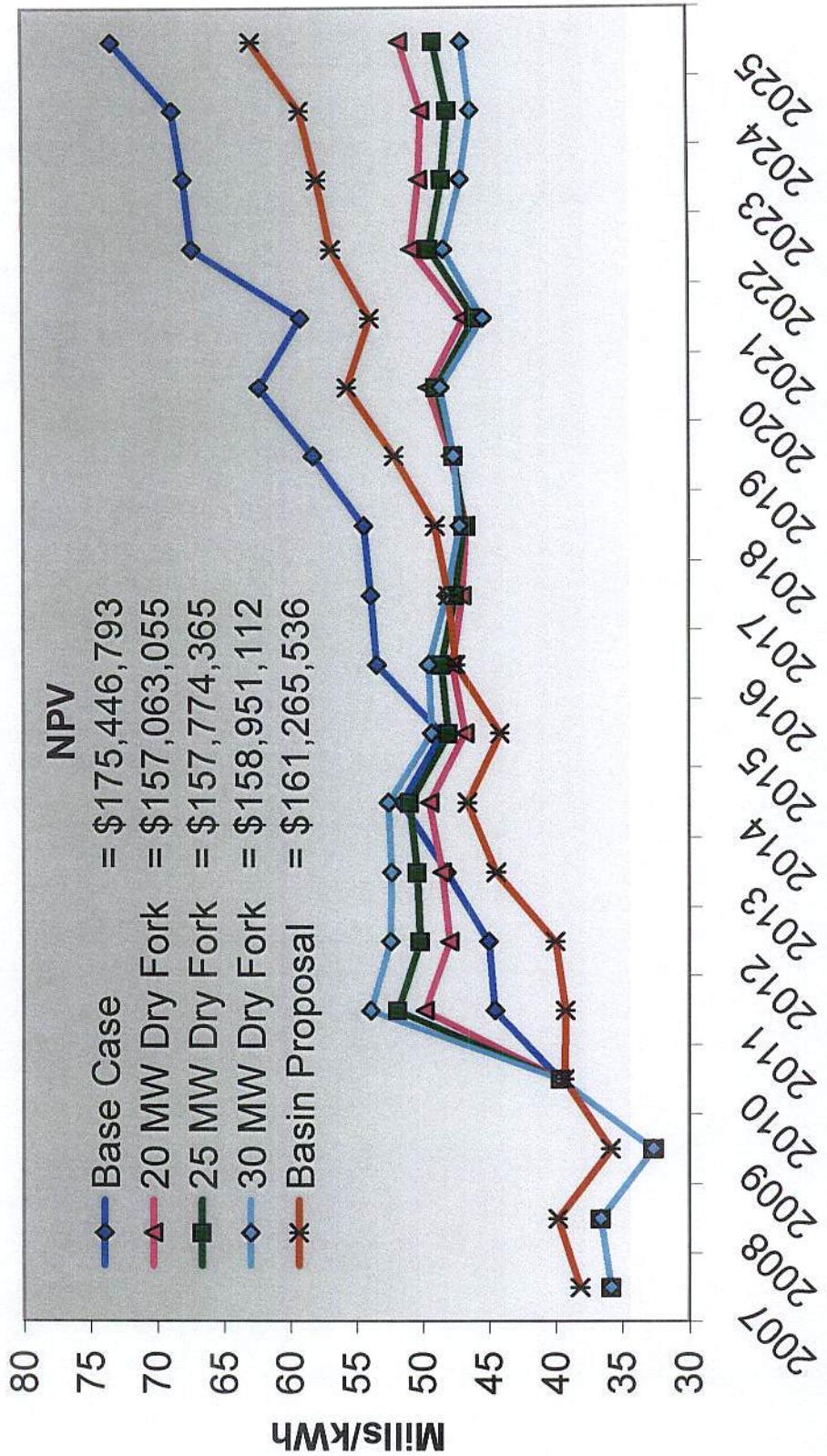
Base Case vs. Low Load Growth Case



Results under Low Load Growth (Analysis of May 06)



Results under Low Load Growth (Analysis of April 07)



Increase in NPV

Low Load Growth Scenario

	May 2006	April 2007	% Change
Base Case	\$175,446,793	\$175,446,793	0.0%
20 MW Dry Fork	\$145,205,050	\$157,063,055	8.2%
25 MW Dry Fork	\$142,951,859	\$157,774,365	10.4%
30 MW Dry Fork	\$141,164,104	\$158,951,112	12.6%
Basin Proposal	\$161,265,536	\$161,265,536	0.0%

Conclusions

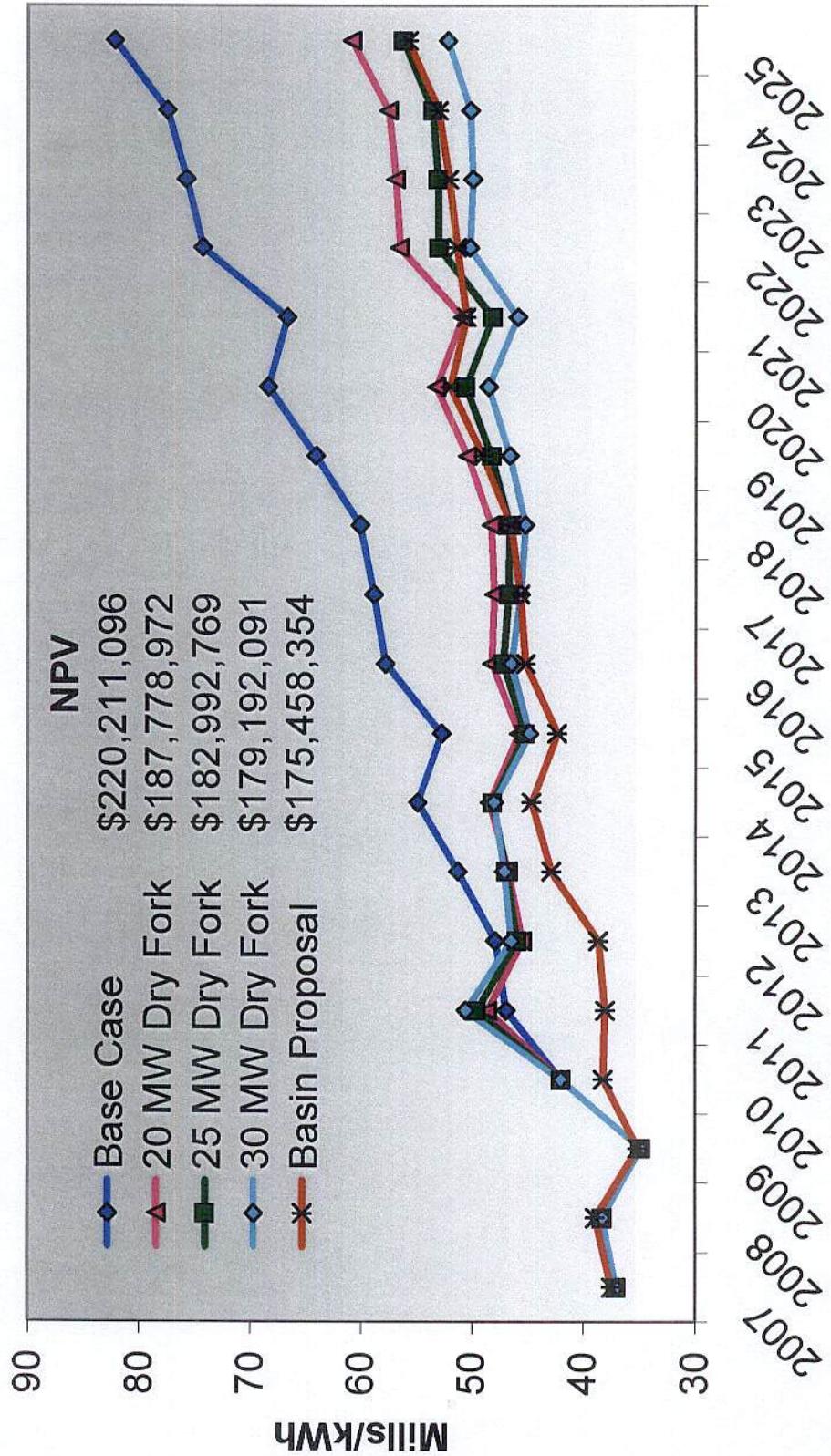
- Agency's analysis was confirmed by R. W. Beck's May 2006 analysis using the same assumptions
- Expected costs of Dry Fork Cases and Basin Case in the May 2006 analysis were not significantly different in net present value. However, under the new Dry Fork capital cost estimates, there is a significant upward shift in the NPV and the associated \$/MWh costs of Dry Fork options.
- Basin Case has more benefit in the early years in both May 2006 and April 2007 analysis. However, its benefits extend for many more years under the new higher Dry Fork capital cost estimates.
- Dry Fork Cases rely on market sales revenues, especially in early years and at higher Dry Fork purchase amounts
- Results are sensitive to key drivers (market sales price and load growth)

Additional Sensitivity Analyses

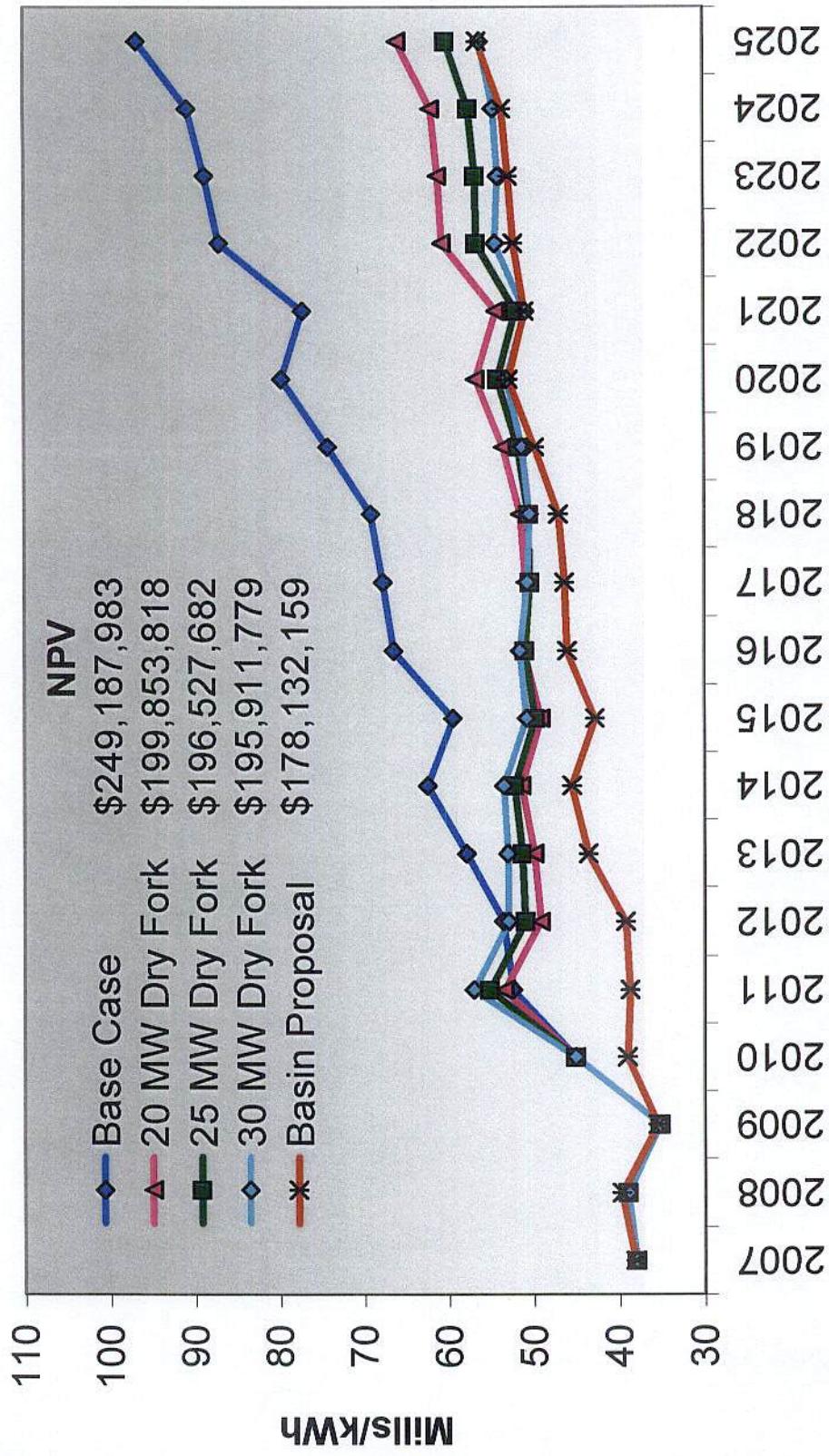
- Additional analyses were performed to explore the impact of increases in sales and purchase prices.
- The three scenarios considered include:
 - 25% increase in Sales Prices
 - 25% increase in Purchase Prices
 - 25% increase in both Sales and Purchase Prices.

Results Under 25% Higher Sales Prices with Purchase Prices Unchanged (Analysis of April 07)

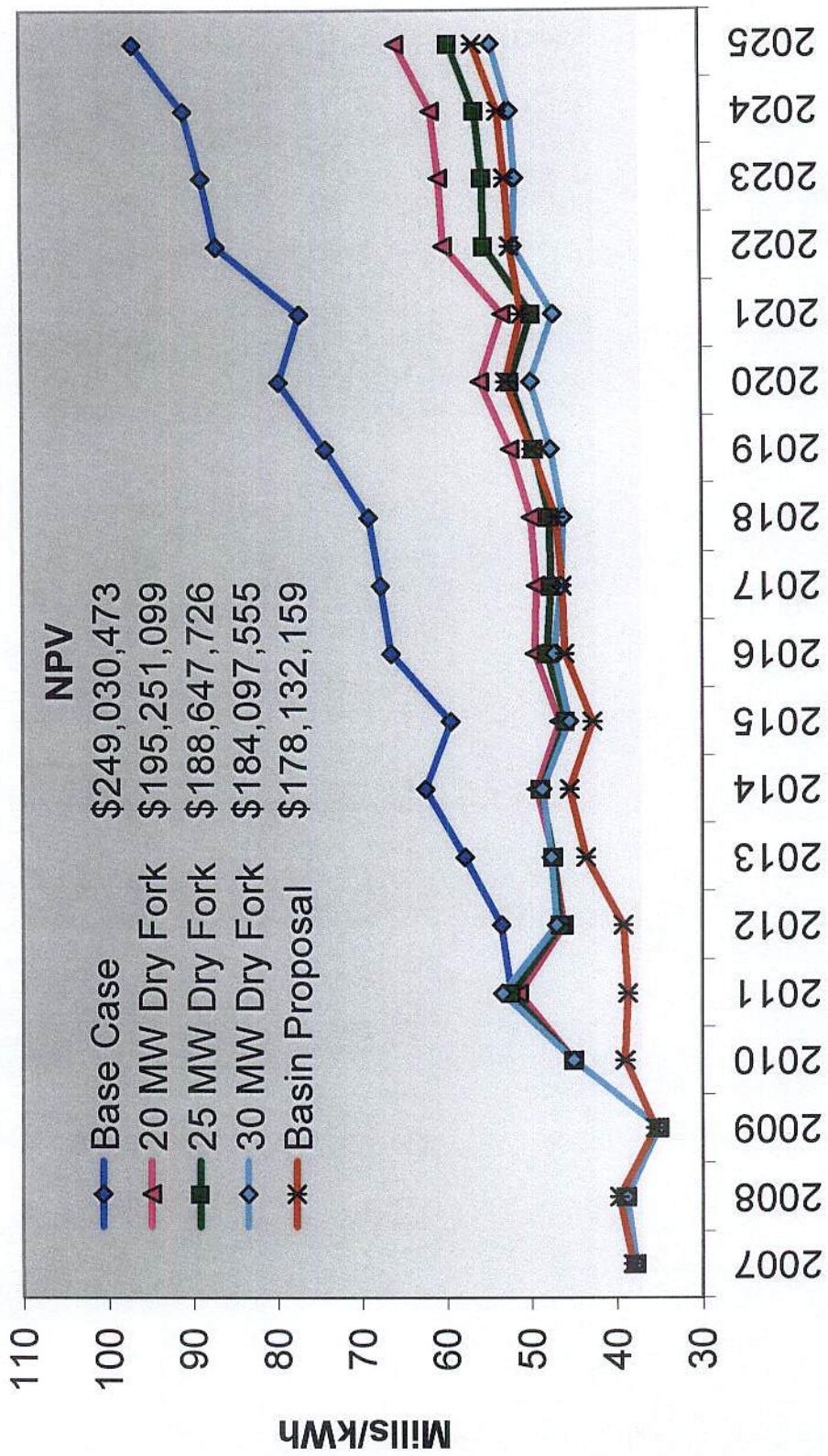
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Results Under 25% Higher Purchase Prices with Sales Prices Unchanged (Analysis Of April 07)



Results under 25% Higher Sales and Purchase Prices (Analysis of April 07)



Results of the Additional Sensitivity Analyses

- 25% Higher Sales Prices improve the NPV of Dry Fork cases compared to the Base Scenario, with the 30 MW Dry Fork case having the lowest NPV.
- 25% Higher Purchase Prices have adverse impact on NPV of Dry Fork cases compared to the Base Scenario, with the 30 MW Dry Fork case still having the lowest NPV.
- Combined 25% Higher Sales and Purchase Prices have mixed impact on Dry Fork cases. The NPV of the 20 MW Dry Fork case increases compared to its NPV in the Base Scenario, whereas the NPV of 25 and 30 MW Dry Fork cases decrease compared to their NPV in the Base Scenario, with the 30 MW Dry Fork case experiencing the greater improvement.
- These results imply that the level of price increases in either or both of sales and purchase prices has a significant impact on the NPV of Dry Fork cases. In addition, the optimal size of the Dry Fork option depends on the sales and purchase price assumptions.
- It should be noted that the analysis results reported here do not cover all the possible future scenarios. A more conclusive study requires a more detailed stochastic analysis covering a combination of range of sales and purchase price increases in order to determine “expected” NPV for each Dry Fork case.

July 27, 2007

via e-mail: llamaack@wmpa.org



Mr. Larry LaMaack
Executive Director
Wyoming Municipal Power Agency
4041 US Hwy 20
Lusk, WY 82225

Subject: **Demand-Side Management Study**

Dear Mr. LaMaack:

At the request of the Wyoming Municipal Power Agency ("WMPA"), R. W. Beck, Inc. ("R. W. Beck") was retained to perform an evaluation of the cost-effectiveness of residential and commercial demand-side management ("DSM") measures for potential implementation by WMPA. The purpose of the study is to supplement certain integrated resource planning ("IRP") analyses and studies currently being undertaken by WMPA for filing with the Western Area Power Administration ("Western"). Comments received from Western in response to a preliminary filing of its 2007 IRP indicated that WMPA should perform addition analyses relating to potential DSM programs and incorporate the results of such DSM analyses with its IRP filing. This letter report is intended to satisfy the requirements of Western that WMPA perform a DSM study as part of its IRP filing.

This study was performed under that certain agreement dated January 26, 2006 between WMPA and R. W. Beck (the "Agreement"). This report has been prepared for the use of WMPA for the specific purposes identified in this report. This report is solely for the information of and assistance to WMPA and should not be relied upon for any other purpose or by any other party unless authorized by R. W. Beck in accordance with the Agreement.

The projections presented in this report were developed on the basis of the assumptions and circumstances described herein. In preparing this report, we have made certain assumptions with respect to conditions that may exist or events that may occur in the future. While we believe the use of such assumptions to be reasonable for the purposes stated herein, we offer no other assurances with respect thereto, and it should be anticipated that some future conditions may vary significantly from those assumed herein due to unanticipated events and circumstances. To the extent that future conditions differ from those assumed in the Analysis, actual results and outcomes may vary from those projected.

The conclusions, observations, and recommendations contained herein attributed to R. W. Beck constitute the opinions of R. W. Beck. To the extent that statements, information, and opinions provided by WMPA or others have been used in the preparation of this report, R. W. Beck has relied upon the same to be accurate and for which no assurances are intended and no representations or warranties are made. R. W. Beck makes no certification and gives no assurances except as explicitly set forth in this report. This report summarizes our work up to the date of this report; changed conditions which occur or become known after such date could affect the results presented in the report to the extent of such changes.

Executive Summary

WMPA is a municipal power agency responsible for providing wholesale power to its Members. WMPA has no authority to provide service to the retail customers of its Members. As such, WMPA cannot provide or cause to be provided DSM programs to its Members' retail customers. Ultimately, it is the WMPA Members that will decide which DSM programs they choose to implement. Even though WMPA cannot cause its members to implement DSM programs, WMPA has conducted this DSM study as part of its IRP filing with Western to investigate whether certain DSM measures may have economic potential for implementation in the WMPA Member electric systems. The DSM study was conducted in a manner to provide a practical investigation of DSM measure potential for the WMPA Members, managing the cost of the study commensurate with the size and scope of the WMPA Member electric systems. The analysis was conducted in two phases: (i) a technical screening assessment; and (ii) an economic screening analysis.

The technical screening assessment involved a review of all DSM measures recommended by Western for consideration by its small customer class of wholesale customers. DSM measures were rated for their potential implementation in the WMPA Member service areas. Those measures whose ratings indicated an average or better potential for implementation were considered for further evaluation during the economic screening analysis. The DSM measures considered, a description of the methodology, and the results of the technical screening assessment are summarized in the report section entitled *Technical Screening Assessment*. Additional detailed results of the technical screening assessment are provided in Appendix A.

The results of the technical screening assessment identified fourteen (14) potential DSM measures for evaluation through an economic screening analysis. Each measure was evaluated for cost-effectiveness by comparing DSM measure costs against marginal supply-side costs that could be avoided if the DSM measures were installed by retail customers of the WMPA Members.

Table 1
DSM Measures Evaluated for Economic Potential

	Residential	Commercial
Energy efficiency equipment measures:		
Boiler/furnace installations/retrofits	X	
Weatherization/insulation retrofit	X	X
Storm windows/doors retrofit	X	
Insulation of boilers, pipes and ducts	X	
Clock thermostats	X	
Energy efficient lighting retrofit	X	X
Renewable energy measures:		
Solar photovoltaic	X	X
Solar thermal	X	X
Energy information programs:		
Energy audits (includes use of infrared heat detection equipment)	X	X

In performing this economic screening analysis, industry-standard techniques and formulae were applied to the evaluation of the DSM measures. Assumptions on DSM measure energy and demand impacts and costs were developed from available information on typical equipment costs, energy savings estimates specific to the WMPA Members' retail customer characteristics, and typical DSM program costs for electric utilities. Specific assumptions used to evaluate each of the DSM measures are presented in Appendix B. The economic screening analysis was performed from the perspective of WMPA (e.g., marginal power supply costs of WMPA were compared to DSM measure costs).

Per the scope of services for this study, projections of DSM program saturations, potential customer penetration rates, and utility incentive programs were not evaluated. Instead, the economic screening was performed by assuming an implementation of 1,000 retail customer participants per DSM measure, beginning with calendar year 2008.

Cost-effectiveness evaluations were performed for three different perspectives, as follows. More detailed descriptions of the cost-effectiveness test can be found in the report section entitled *DSM Benefit-Cost Tests*.

Utility Cost Test – A measure of whether the benefits of avoided utility costs are greater than the costs incurred by the utility to implement the DSM program.

Rate Impact Measure (RIM) Test – A measure of whether utility rate-payers that do not participate in a DSM program would see an increase in retail rates as a result of other customers participating in a utility-sponsored DSM program.

Total Resource Cost (TRC) Test – A measure of whether the combined benefits of the utility and customers participating in the DSM program are greater than the combined costs to implement the DSM program.

Summary results of the economic screening are presented below in Table 2. The table provides present value benefit to cost ratios computed over a twenty-year study period from 2008 through 2027 for each DSM measure for each of the cost-effectiveness test described above.

WMPA has established that a DSM measure must pass both the Utility Cost Test and the RIM Test before WMPA would promote a DSM measure as part of its IRP filing. A benefit to cost ratio of greater than 1.0 for the Utility Cost Test and the RIM Test indicates that a WMPA Member could promote and develop a given DSM program such that the program would reduce WMPA operating costs at a level greater than the Member's cost of the program and that net benefits derived from the program would not cause an increase in the retail rates charged to its Members or the wholesale rates of other WMPA Members.

None of the DSM measures evaluated for economic potential were found to pass both the Utility Cost and RIM Test criteria. As such, WMPA is not including any projections of DSM impacts in its IRP filing. However, ultimately it is each WMPA Member that will choose whether to implement a DSM measure. A Member may choose to implement DSM programs for reasons that are different than the economic conditions considered by WMPA. For instance, a Member may choose to ignore adverse retail rate impacts and implement DSM programs based on the TRC Test results. Furthermore, it is our understanding that the WMPA Members will continue

Demand-Side Management Study

July 27, 2007

Page 4

to implement their existing electric utility facility maintenance and efficiency programs, that WMPA will continue to offer public information programs on energy conservation, and that WMPA will continue to support and assist its Members' implementation of DSM programs.

Table 2
Summary Results of DSM Cost-Effectiveness

	Benefit/Cost Ratio		
	Utility Cost Test	RIM Test	TRC Test
Residential Measures:			
Boiler/furnace installations/retrofits	1.463	0.530	0.813
Weatherization/insulation retrofit	4.268	0.696	1.423
Storm windows/doors retrofit	9.365	0.764	1.338
Insulation of boilers, pipes and ducts	6.793	0.741	1.132
Clock thermostats	37.441	0.813	1.070
Energy efficient lighting retrofit	29.353	0.730	4.193
Solar photovoltaic	40.418	0.744	0.205
Solar thermal	21.508	0.679	0.416
Residential energy audits	2.094	0.592	0.722
Commercial Measures:			
Weatherization/insulation retrofit	50.959	0.728	1.040
Energy efficient lighting retrofit	13.833	0.889	1.258
Solar photovoltaic	40.418	0.888	0.258
Solar thermal	21.508	0.809	0.416
Commercial energy audits	2.636	0.568	0.694

Approach & Methodology

Technical Screening Assessment

The technical screening assessment involved a review of all DSM measures recommended by Western for consideration by its small customer class of wholesale customers, as identified in the first column of Table 3, below. Each potential DSM measure was rated for its appropriateness for implementation in the WMPA Members' systems based on local knowledge of retail customer end-use characteristics (e.g., appliance saturation, dwelling and building types and ages, and saturation of industrial classifications) and whether a given DSM measure was likely to be adopted by the retail customers in the WMPA Members service areas.

Each potential DSM measure was ranked from low to high (numerically, 0 to 5, with 5 indicating a high potential for implementation). Additionally, DSM and utility maintenance programs that are already being implemented by WAPA and/or its Members were coded as 0, indicating no new DSM initiatives are required. DSM measures were ranked independently for the residential and commercial retail classes and for utility facilities and services. Those DSM

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Measures whose ratings indicated an average or better potential for implementation were considered for further evaluation in the economic screening analysis. Summary results of the technical screening assessment are contained below in Table 3. Additional results are provided in Appendix A.

Table 3
Summary Results of DSM Technical Screening

	Applicability to WMPA Member Customers		
	Residential	Commercial	Utility
Energy efficiency equipment measures:			
Boiler/furnace retrofits/installations	3	2	
Air conditioning retrofits/installations	1	2	
Heat pumps retrofits/installations	1	1	
Weatherization, insulation	4	3	
Storm windows/doors	3	1	
Insulation of air ducts	1	2	
Insulation of boilers and pipes	3	2	
Clock thermostats and equipment system timers (summer)	1	1	
Clock thermostats and equipment system timers (winter)	3	1	
Energy efficient lighting	4	4	
Electric motor replacements			1
Renewable energy measures:			
Solar photovoltaic	4	4	
Solar thermal	4	4	
Day lighting technologies		1	
Energy information programs:			
Energy audits	3	3	
Public education programs	0	0	
Use of infrared heat detection equipment	3	3	
Equipment inspection programs	2	2	0
Utility efficiency measures:			
Upgrading of distribution lines/substation equipment			0
Power factor improvement			0
Distribution efficiency upgrades and maintenance			0
Street lighting			0
Load management measures:			
Load management (HVAC)	1	1	
Load management (water heating)	1	1	
Demand control techniques and equipment		1	
Smart meters or automated equipment	1	1	
Time-of-use meters	1	1	
Rate design:			
Time-of-day rates	1	1	
Seasonal rates	1	1	
Interruptible rates		1	
Scoring:	5 – Highly applicable to the WMPA Member retail customers.		
	1 – Low applicability to the WMPA Member retail customers.		
	0 – Existing program; no new initiative required.		

Economic Screening Analysis

Based on the results of the technical screening analysis, fourteen (14) potential DSM measures were identified for further evaluation in the economic screening analysis (see Table 4). As described below, industry-standard economic benefit-cost evaluations were used to evaluate the economic potential of each DSM measure. As described in the following section, assumptions on DSM measure energy and demand impacts and costs were developed from available information on typical equipment costs, energy savings estimates specific to the WMPA Members' retail customer characteristics, and typical DSM program costs for electric utilities. Potential avoided marginal costs for WMPA were based on the latest integrated resource plans developed by WMPA. The economic analysis was conducted for a twenty-year study period (2008 through 2027).

Table 4
DSM Measures Evaluated for Economic Potential

	Residential	Commercial
Energy efficiency equipment measures:		
Boiler/furnace installations/retrofits	X	
Weatherization/insulation retrofit	X	X
Storm windows/doors retrofit	X	
Insulation of boilers, pipes and ducts	X	
Clock thermostats	X	
Energy efficient lighting retrofit	X	X
Renewable energy measures:		
Solar photovoltaic	X	X
Solar thermal	X	X
Energy information programs:		
Energy audits (includes use of infrared heat detection equipment)	X	X

DSM Measure Assumptions

Table 5 provides a general description of each DSM measure. More detailed modeling assumptions, including utility and customer DSM cost and load impact, can be found in Appendix B. Customer participation levels were assumed to be 1,000 in 2008, with no incremental participants through the end of the study period. By modeling the DSM measure installations at the first year of the study, the DSM measures were modeled to have the greatest possible net present benefits. As required, new DSM measure installations were modeled to occur at the end of the useful life of the measure to maintain the persistence of the DSM demand and energy reductions over the study period.

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Table 5
DSM Measure Descriptions

DSM Measure	General Description
Residential Measures:	
Boiler/furnace installations/retrofits	Install high-efficiency electric boiler or furnace in new construction or replace standard efficiency boiler or furnace with high-efficiency unit at time of replacement.
Weatherization/insulation retrofit	Retrofit existing dwellings with additional insulation and new weather-stripping.
Storm windows/doors retrofit	Retrofit existing dwellings with new storm windows and doors.
Insulation of boilers, pipes and ducts	Retrofit/repair existing HVAC distribution systems and add new/additional insulation.
Clock thermostats	Retrofit existing HVAC system with clock thermostat.
Energy efficient lighting retrofit	Retrofit existing incandescent and fluorescent lamps with compact fluorescent and high-efficiency fluorescent lamps.
Solar photovoltaic	Install solar photovoltaic electric generation system at residential dwelling.
Solar thermal	Install solar thermal water heating system at residential dwelling.
Residential energy audits	Dwelling energy efficiency and infrared heat detection audits conducted by utility.
Commercial Measures:	
Weatherization/insulation retrofit	Retrofit existing small commercial businesses with additional insulation and weather-stripping.
Energy efficient lighting retrofit	Retrofit existing incandescent and fluorescent lamps, compact fluorescent, HID, and high-efficiency fluorescent lamps and fixtures.
Solar photovoltaic	Install solar photovoltaic electric generation system at business.
Solar thermal	Install solar thermal water heating system at business.
Commercial energy audits	Business energy efficiency and infrared heat detection audits conducted by utility.

WMPA Cost Assumptions

Evaluation of DSM measures requires a comparison of DSM measure costs against avoidable utility operating and capital costs. In general, the modeled utility cost and system characteristics include the following:

- Avoidable capital costs for future WMPA generation facilities;
- Avoidable O&M costs for future WMPA generation facilities;
- Avoidable WMPA transmission costs;
- WMPA and Member T&D losses;
- WMPA financing costs and assumptions;
- Projections of average base (non-fuel) retail rates for the WMPA Members; and
- Projections of average and marginal WMPA fuel and purchased power costs.

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These assumptions were developed from a number of sources, including the latest WMPA IRP analyses, fuel and power market price projections, and WMPA Member retail rates. The sources and derivation of these assumptions, along with other major assumptions utilized for this study, are documented in Appendix B. Modeled annual and present value WMPA electric system costs, rates, and characteristics are presented in Appendix C for two example DSM measures.

DSM Benefit-Cost Tests

For this study, industry standardized formulae were adopted for computing DSM measure costs and benefits. We have relied upon three of the standard tests for this study: the Utility Cost Test, the Rate Impact Measure (RIM) Test, and the Total Resource Cost (TRC) Test. In general terms, the equations that define the three standard tests can be described as follows.

Utility Cost Test:

Benefits	=	Avoided Energy Supply Costs (net generation level decreases × marginal energy costs)
	+	Avoided Capital Supply Costs (net generation level decreases × incremental capital costs)
	+	Avoided O&M Supply Costs (net gen. or distrib. level decreases × marginal O&M costs)
	+	Participation Charges
Costs	=	Increased Energy Supply Costs (net generation level increases × marginal energy costs)
	+	Increased Capital Supply Costs (net generation level increases × incremental capital costs)
	+	Increased O&M Supply Costs (net gen. or distrib. level increases × marginal O&M costs)
	+	Utility program costs (administrative costs)
	+	Incentives (utility incentives, rebates, etc.)

Rate Impact Measure (RIM) Test:

Benefits	=	Avoided Energy Supply Costs (net generation level decreases × marginal energy costs)
	+	Avoided Capital Supply Costs (net generation level decreases × incremental capital costs)
	+	Avoided O&M Supply Costs (net gen. or distrib. level decreases × marginal O&M costs)
	+	Revenue Gains (net meter level increases × retail rates)
	+	Participation Charges
Costs	=	Increased Energy Supply Costs (net generation level increases × marginal energy costs)
	+	Increased Capital Supply Costs (net generation level increases × incremental capital costs)
	+	Increased O&M Supply Costs (net gen. or distrib. level increases × marginal O&M costs)
	+	Revenue Losses (net meter level decreases × retail rates)
	+	Utility program costs (administrative costs)
	+	Incentives (utility incentives, rebates, etc.)

Total Resource Cost (TRC) Test:

Benefits	=	Avoided Energy Supply Costs (net generation level decreases × marginal energy costs)
	+	Avoided Capital Supply Costs (net generation level decreases × incremental capital costs)
	+	Avoided O&M Supply Costs (net gen. or distrib. level decreases × marginal O&M costs)
	+	Avoided Participant Costs (avoided capital, O&M, etc.)
	+	Tax Credits
Costs	=	Increased Energy Supply Costs (net generation level increases × marginal energy costs)
	+	Increased Capital Supply Costs (net generation level increases × incremental capital costs)
	+	Increased O&M Supply Costs (net gen. or distrib. level increases × marginal O&M costs)
	+	Incremental Participant Costs (capital costs, O&M, etc.)
	+	Utility DSM Program A&G Costs

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Detailed cost and benefit computations for each standard test are provided in Appendix C for the evaluation of two example DSM measures (residential and commercial energy audits). The computations reflect all incurred incremental costs and avoided incremental costs (benefits) that were used to evaluate the DSM measures.

Results

WMPA has established that a DSM measure must pass both the Utility Cost Test and the RIM Test before WMPA would promote a DSM measure as part of its IRP filing. A benefit to cost ratio of greater than 1.0 for the Utility Cost and RIM Tests indicates that a WMPA Member could promote and develop a given DSM program such that the program would reduce WMPA operating costs at a level greater than the Member's and/or WMPA's cost of implementing the program and that the program would not cause an increase in the retail rates charged by its Members or the wholesale rates charged by WMPA. A summary of net benefits (or costs) and the benefit to cost ratio are provided for each evaluated DSM measure in Table 6.

Table 6
Summary Results of DSM Cost-Effectiveness

	NPV Benefit (Costs) (\$000)			Benefit/Cost Ratio		
	Utility Cost Test	RIM Test	TRC Test	Utility Cost Test	RIM Test	TRC Test
Residential Measures:						
Boiler/furnace installations/retrofits	176	(492)	(128)	1.463	0.530	0.813
Weatherization/insulation retrofit	269	(153)	104	4.268	0.696	1.423
Storm windows/doors retrofit	688	(238)	194	9.365	0.764	1.338
Insulation of boilers, pipes and ducts	476	(196)	65	6.793	0.741	1.132
Clock thermostats	300	(71)	20	37.441	0.813	1.070
Energy efficient lighting retrofit	420	(161)	331	29.353	0.730	4.193
Solar photovoltaic	8,278	(2,921)	(32,901)	40.418	0.744	0.205
Solar thermal	1,556	(770)	(2,293)	21.508	0.679	0.416
Residential energy audits	249	(328)	(183)	2.094	0.592	0.722
Commercial Measures:						
Weatherization/insulation retrofit	5,685	(2,167)	223	50.959	0.728	1.040
Energy efficient lighting retrofit	1,902	(255)	420	13.833	0.889	1.258
Solar photovoltaic	16,555	(2,140)	(48,803)	40.418	0.888	0.258
Solar thermal	1,556	(386)	(2,293)	21.508	0.809	0.416
Commercial energy audits	727	(892)	(518)	2.636	0.568	0.694

None of the DSM measures evaluated for economic potential were found to pass both the Utility Cost and RIM Test criteria. As such, WMPA is not including any projections of DSM impacts in its IRP filing. However, ultimately it is each WMPA Member that will choose whether to implement a DSM measure. A Member may choose to implement DSM programs for reasons that are different than the economic conditions considered by WMPA. For instance, a Member

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may choose to ignore adverse retail rate impacts and implement DSM programs based on the TRC Test results. Furthermore, it is our understanding that the WMPA Members will continue to implement their existing electric utility facility maintenance and efficiency programs, that WMPA will continue to offer public information programs on energy conservation, and that WMPA will continue to support and assist its Members' implementation of DSM programs.

Should you have any questions, please feel free to give me a call at (407) 648-3573.

Sincerely,

R. W. BECK, INC.



Robert L. Davis
Senior Director

RLD/rld

APPENDIX A

Technical Screening Assessment

Technical Screening Assessment

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Applicable to WMPA Member Systems & Customers					
	Residential	Commercial	Utility		Comments
Energy efficiency equipment measures:					
• Boiler/furnace retrofits/installations	3	2		Moderate saturation of older boiler systems in residential dwellings. Limited saturation in commercial businesses.	
• Air conditioning retrofits/installations	1	2		Low saturation of central AC in residential dwellings. Limited saturation of central AC systems in commercial businesses.	
• Heat pumps retrofits/installations	1	1		Not applicable. Ambient conditions prohibit air-to-air. Limited access to ground water.	
• Weatherization, insulation	4	3		Good to moderate applicability for residential and commercial due to age of dwellings and buildings.	
• Storm windows/doors	3	1		Good applicability for residential due to age of dwellings. Low saturation in commercial businesses.	
• Insulation of air ducts	1	2		Limited to low saturation of forced air HVAC systems in residential and commercial businesses.	
• Insulation of boilers and pipes	3	2		Moderate saturation of older boiler systems in residential. Low saturation in commercial businesses.	
• Clock thermostats and equipment system timers (summer)	1	1		Low saturation of central AC in residential. Generally not applicable for commercial businesses.	
• Clock thermostats and equipment system timers (winter)	3	1		Moderate saturation of boiler systems in residential dwellings. Generally not applicable for commercial businesses.	
• Energy efficient lighting	4	4		Good potential.	
• Electric motor replacements			0	Limited industrial establishments. Limited municipal pumping systems. Existing utility maintenance program.	

Scoring: 5 – Highly applicable to the WMPA Member systems.

1 – Low applicability to the WMPA Member systems.

0 – Not applicable; or existing program, no new initiative required.

Technical Screening Assessment

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Applicable to WMPA Member Systems & Customers				
	Residential	Commercial	Utility	Comments
Renewable energy measures:				
• Solar photovoltaic	4	4		Relatively high solar incidence. (Note: Net metering already available for PV system installations.)
• Solar thermal	4	4		Relatively high solar incidence.
• Day lighting technologies		1		Limited application, new installations only.
Energy information programs:				
• Energy audits	3	3		Possible but relatively high cost due to relatively small utility size and proximity of WMPA Members to each other.
• Public education programs	0	0		Possible web-based distribution.
• Use of infrared heat detection equipment	3	3		Possible as part of potential energy audit program if Western continues equipment supply program.
• Equipment inspection programs	2	2	0	Low to moderate saturation of older systems requiring inspections. Existing utility maintenance program.
Utility efficiency measures:				
• Upgrading of distribution lines/substation equipment			0	Existing utility maintenance program.
• Power factor improvement			0	Existing utility program.
• Distribution efficiency upgrades and maintenance			0	Existing utility program.
• Street lighting			0	More than 90% of street lighting already converted to HPS. Existing programs to complete conversions during regular maintenance.

Scoring: 5 – Highly applicable to the WMPA Member systems.

1 – Low applicability to the WMPA Member systems.

0 – Not applicable; or existing program, no new initiative required.

Technical Screening Assessment

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		Applicable to WMPA Member Systems & Customers			
		Residential	Commercial	Utility	Comments
Load management measures:					
• Load management (HVAC)		1	1		Low saturation of central AC systems (summer peaking utility systems).
• Load management (water heating)		1	1		Low saturation of electric water heating.
• Demand control techniques and equipment			1		Low saturation of industrial installations or not conducive to control (hospitals, schools, large retail).
• Smart meters or automated equipment		1	1		Limited DSM potential. Currently under consideration as means to reduce utility operating costs.
• Time-of-use meters		1	1		Limited potential due to low saturation of controllable electric loads.
Rate design:					
• Time-of-day rates		1	1		Low potential due to low saturation of controllable electric loads.
• Seasonal rates		1	1		Low saturation of seasonal customers.
• Interruptible rates			1		Low saturation of industrial installations or not conducive to interruption (hospitals, schools, large retail).
Agricultural energy efficiency measures:					
• Irrigation pump utilization/scheduling			0		Insignificant agricultural loads.
• Irrigation pump testing or efficiency improvements			0		Insignificant agricultural loads.
• Electric motor replacement			0		Insignificant agricultural loads.
• Photovoltaic pumping systems			0		Insignificant agricultural loads.
• Ditch lining or piping			0		Insignificant agricultural loads.
• Laser land leveling			0		Insignificant agricultural loads.
• Pump back systems			0		Insignificant agricultural loads.
• Water conservation programs			0		Insignificant agricultural loads.

Scoring: 5 – Highly applicable to the WMPA Member systems.

1 – Low applicability to the WMPA Member systems.

0 – Not applicable, or existing program, no new initiative required.

APPENDIX B

Economic Screening Modeling Assumptions



WMPA DSM STUDY

Major Modeling Assumptions

The following descriptions document the major modeling assumptions used for the WMPA DSM Study. Assumptions are organized and numbered to be consistent with the titles and item or column numbers reported in the detailed DSM measure evaluation reports presented in Appendix C. Documented assumptions include inputs and projections of incremental and average costs and system operating conditions for the WMPA electric system and assumptions for DSM measures, some of which are also presented below in Table A-1.

INPUT DATA — I. PROGRAM DEMAND SAVINGS AND LINE LOSSES

- (1) Customer Non-Coincident kW Reduction at Meter**
Varies by DSM measure. See Table B-1.
- (1.1) Customer kW Reduction Peak Coincidence Factor**
Varies by DSM measure. See Table B-1.
- (1.2) Customer kWh Reduction at Meter**
Varies by DSM measure. See Table B-1.
- (1.3) Customer Coincident kW Reduction at Meter**
Varies by DSM measure. See Table B-1.
- (1.4) Generation Expansion Reserve Margin**
Based on the WMPA IRP.
- (2) Generator kW Reduction per Customer**
Derived from assumed customer coincident kW reduction at the meter, adjusted for assumed generator expansion reserve margin, assumed system kW line losses, and group line loss multiplier.
- (3) System kW Line Loss Percentage**
Assumed to be identical to the System kWh Line Loss Percentage (see below).
- (4) Generator kWh Reduction per Customer**
Derived from customer kWh reduction at the meter, adjusted for assumed system kWh line losses and group line loss multiplier.
- (5) System kWh Line Loss Percentage**
Assumed 11% combined transmission and distribution losses.
- (6) Group Line Loss Mult. (Delivery Voltage Adj.)**
Not applicable for residential and small commercial customers.
- (7) Customer kWh Program Increase at Meter**
Reflects any DSM-induced increases in consumption or DSM-induced shifting of energy consumption from on- to off-peak periods. Varies by DSM measure; however, none assumed for this DSM study.

INPUT DATA — II. ECONOMIC LIFE, K-FACTOR AND FINANCING RATES

- (1) Study Period for Conservation Programs**
Twenty-year study period was modeled for this study.
- (2) Generator Economic Life**
Assumption based on an industry standard of 30 years.
- (3) T&D Economic Life**
Assumption based on an industry standard of 25 years.
- (4) K-Factor for Generation**
Not applicable. Municipal-type financing assumed.
- (5) K-Factor for T&D**
Not applicable. Municipal-type financing assumed.
- (6.1) Utility Discount Rate**
Assumed to be identical to the Utility Debt Rate (see below).
- (6.2) Utility Debt Rate**
Assumed 7%, based on WMPA IRP.
- (6.3) Insurance Rate**
Assumed 0.36%, based on WMPA IRP.
- (6.4) Return to City**
Not applicable.

INPUT DATA — III. UTILITY AND CUSTOMER COSTS

- (1) Utility Non-Recurring Cost per Customer**
Based on industry standard utility costs for DSM programs consistent with DSM measure. Varies by DSM measure. See Table B-1.
 - (1.1) Utility Non-Recurring Cost Escalation rate**
Cost escalation at assumed annual inflation rate of 2.4%.
 - (2) Utility Recurring Cost per Customer**
None assumed.
 - (3) Utility Recurring Cost Escalation rate**
None assumed.
 - (4) Customer Equipment Cost**
Varies by DSM measure. See Table B-1.
 - (5) Customer Equipment Cost Escalation Rate**
Cost escalation at assumed annual inflation rate of 2.4%.
 - (6) Customer O&M Cost**
Varies by DSM measure. See Table B-1.
-

-
- (7) **Customer O&M Cost Escalation Rate**
Cost escalation at assumed annual inflation rate of 2.4%.
 - (8.1) **Utility Non-Recurring Rebate/Incentive**
Based on industry standard utility costs for DSM programs consistent with DSM measure. Varies by DSM measure. See Table B-1.
 - (8.2) **Utility Non-Recurring Rebate/Incentive Esc**
Cost escalation at assumed annual inflation rate of 2.4%.
 - (8.3) **Utility Recurring Rebate/Incentive**
None assumed.
 - (8.4) **Utility Recurring Rebate/Incentive Esc**
None assumed.

INPUT DATA — IV. AVOIDED GENERATOR, TRANS. AND DIST. COSTS

- (1) **Base Year**
Base year for study is 2008.
- (2) **In-Service Year for Avoided Generating Unit**
Assumed 2011 based on WMPA IRP.
- (3) **In-Service Year for Avoided T&D**
No avoidable T&D facilities assumed.
- (4) **Base Year Avoided Generating Unit Cost**
Assumed \$3,440 based on WMPA IRP.
- (5) **Base Year Avoided Transmission Cost**
No avoidable transmission facility costs. Avoidable transmission wheeling modeled as transmission fixed O&M. See #10, below.
- (6) **Base Year Avoided Distribution Cost**
No avoidable distribution costs.
- (7) **Gen, Tran, & Dist Cost Escalation Rate**
Assumed annual inflation rate of 2.4%.
- (8) **Generator Fixed O&M Cost**
Assumed 27.70 based on WMPA IRP.
- (9) **Generator Fixed O&M Rate**
Assumed annual inflation rate of 2.4%.
- (10) **Transmission Fixed O&M Cost**
Assumed \$20.00 per kW-yr based on WMPA IRP.

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- (11) Distribution Fixed O&M Cost**
No avoidable distribution costs.
 - (12) T&D Fixed O&M Escalation Rate**
Assumed annual inflation rate of 2.4%.
 - (13) Avoided Gen Unit Variable O&M Costs**
Assumed \$0.26 per kWh based on WMPA IRP. Includes cost of SO2 allowances.
 - (14) Generator Variable O&M Cost Escalation Rate**
Assumed annual escalation rate of 2.44%.
 - (15) Generator Capacity Factor**
See Supplemental Annual Input Data.
 - (16) Avoided Generating Unit Fuel Cost**
See Supplemental Annual Input Data.
 - (17) Avoided Generating Unit Fuel Escalation Rate**
See Supplemental Annual Input Data.
 - (18.1) Avoided Purchase Capacity Cost per kW**
Not applicable.
 - (18.2) Capacity Cost Escalation Rate**
Not applicable (applies to purchase capacity cost).

INPUT DATA — V. NON-FUEL ENERGY AND DEMAND CHARGES

- (1) Non-Fuel Cost in Customer Bill**
Residential and commercial non-fuel base rate derived from historical average retail rates of WMPA Members, reduced for projections of fuel portion of WMPA wholesale power costs based on WMPA IRP.
- (2) Non-Fuel Cost Escalation Rate**
Based on projections of non-fuel portions of WMPA wholesale power costs plus Member cost portion of retail rates escalated at inflation.
- (3) Customer Demand Charge per kW**
Not modeled.
- (4) Demand Charge Escalation Rate**
Not modeled.
- (5.1) Customer Annual kW Billing Factor Adjustment**
Not modeled.
- (5.2) Group Line Loss Energy Bill Mult (Del Volt Adj)**
Not modeled.

INPUTS — VI. NATURAL GAS CONVERSION

No natural gas conversion effects were assumed or modeled.

ANNUAL INPUT DATA

(2) Cumulative Participating Customers (New Cust.)

For ease of reporting, 1,000 participating customers (installed DSM measures) were modeled. New DSM measure installations were added at the end of the useful life of the DSM measure. DSM measure lives are referenced in Table B-1. Assumption is used to model participant and utility non-recurring DSM costs.

(3) Adjusted Cumulative Participating Customers (Recur. Cust.)

For ease of reporting, 1,000 participating customers were modeled. Assumption is used to model participant and utility recurring DSM costs and DSM energy and demand reductions.

(4) Utility Average System Fuel Costs

Derived from projections of generation fuel costs and purchase power costs modeled for WMPA IRP.

(5) Avoided Marginal Fuel Cost

Derived from power market price projections developed by R. W. Beck for the general Rockies market area. Market prices reflect load weighed average marginal price of power.

(6) Increased Marginal Fuel Cost

Assumed to be equal to Avoided Marginal Fuel Cost.

(7) Replacement Fuel Cost

Assumed to be equal to Avoided Marginal Fuel Cost.

(8) Program kW Effectiveness Factor

All DSM measure installations are assumed to produce 100% of anticipated reductions. No adjustments made for effects of free-riders, premature appliance attrition, or other effects that can reduce DSM program effectiveness.

(8) Program kWh Effectiveness Factor

All DSM measure installations are assumed to produce 100% of anticipated reductions. No adjustments made for effects of free-riders, premature appliance attrition, or other effects that can reduce DSM program effectiveness.

(10) Nat Gas Commodity & Trans Fuel Costs

Not applicable.

SUPPLEMENTAL ANNUAL INPUT DATA

(2) Avoided Generating Unit Capacity Factor

Derived from projections of Dry Fork resource dispatch from WMPA IRP.

-
- (3) Avoided Generating Unit Fuel Cost**
Derived from projections of Dry Fork resource dispatch from WMPA IRP.
 - (5) Increased Supply Cost**
No supplemental DSM program costs were modeled.
 - (6) Other Costs – Partic. Test**
No supplemental DSM program costs were modeled.
 - (7) Other Costs – RIM Test**
No supplemental DSM program costs were modeled.
 - (8) Other Costs – TRC Test**
No supplemental DSM program costs were modeled.
 - (9) Other Benefits – Partic. Test**
No supplemental DSM program benefits were modeled.
 - (10) Other Benefits – RIM Test**
No supplemental DSM program benefits were modeled.
 - (11) Other Benefits – TRC Test**
No supplemental DSM program benefits were modeled.

Table B-1
DSM Measure Cost and Energy Assumptions
(2008 \$)

DSM Measures	DSM Technology	Incremental Equipment Costs			Utility DSM Program Costs		Energy & Demand Reductions		
		Measure Life (years)	Installed Cost (\$)	Annual O&M Cost (\$/yr)	Tax Credits, Non-Utility Rebates (\$)	Non-Recurring Utility Cost (\$)	Annual Energy Reduction (kWh)	Non-Coincident Demand Reduction (kW)	Summer Peak Demand Reduction (kW)
Residential Measures:-									
Boiler/furnace installations/retrofits	Install/replace existing boiler/furnace with high efficiency system. Utility rebate.	15	400.00	-	-	50.00	200.00	775	0.44
Weatherization/insulation retrofit	Retrofit insulation, weatherstripping, and caulking	10	100.00	-	-	50.00	-	490	0.28
Storm windows/doors retrofit	Install storm windows and doors.	10	300.00	-	-	50.00	-	1,075	0.61
Insulate boilers, pipes and ducts	Retrofit/repair uninsulated boilers, pipes and ducts in electric HVAC systems.	10	250.00	-	-	50.00	-	780	0.45
Clock thermostats	Programmable clock thermostat. Utility promotion through public information programs.	10	170.00	-	-	5.00	-	430	0.25
Energy efficient lighting retrofit	Replace 10 existing 60W incandescent with CFL Lamps. Utility promotion through public information programs	5	30.00	-	-	5.00	-	675	0.46
Solar photovoltaic	5kW PV system	20	45,000.00	90.00	(5,000.00)	210.00	-	13,000	5.00
Solar thermal	Solar WH system to replaces 40 gal electric WH.	15	3,500.00	10.00	(1,050.00)	50.00	-	2,700	4.50
Residential energy audits	Customer implements low-cost recommendations, providing 10% reduction in typical customer energy use.	7	190.00	-	-	100.00	-	670	0.17
Commercial Measures:-									
Weatherization/insulation retrofit	Retrofit insulation, weatherstripping, and caulking in small commercial businesses.	7	2,400.00	-	-	50.00	-	8,000	1.83
Energy efficient lighting retrofit	CFL and efficient fluorescent relamping/delamping for typical commercial customer.	5	500.00	-	-	50.00	-	3,000	0.70
Solar photovoltaic	10 kW PV system	20	90,000.00	180.00	(27,000.00)	420.00	-	26,000	10.00
Solar thermal	Solar WH system to replaces 40 gal electric WH.	15	3,500.00	10.00	(1,050.00)	50.00	-	2,700	4.50
Commercial energy audits	Customer implements low-cost recommendations, providing 10% reduction in typical small commercial customer energy use.	5	420.00	-	-	150.00	-	1,650	0.33

APPENDIX C

Example Benefit-Cost Calculations

INPUT DATA
PROGRAM: RESIDENTIAL ENERGY AUDIT (99R-AUDIT)

<u>I. PROGRAM DEMAND SAVINGS AND LINE LOSSES</u>		<u>IV. AVOIDED GENERATOR, TRANS. AND DIST. COSTS</u>	
(1) CUSTOMER NON-COINCIDENT KW REDUCTION AT METER	0.117 KW/CUST	(1) BASE YEAR	2008
(1.1) CUSTOMER KW REDUCTION PEAK COINCIDENCE FACTOR	0.300	(2) IN-SERVICE YEAR FOR AVOIDED GENERATING UNIT	2011
(1.2) CUSTOMER KW REDUCTION AT METER	670 KWH/CUST/YR	(3) IN-SERVICE YEAR FOR AVOIDED T & D	2008
(1.3) CUSTOMER COINCIDENT KW REDUCTION AT THE METER	0.05 KW/CUST	(4) BASE YEAR AVOIDED GENERATING UNIT COST	3,440 \$/KWH
(1.4) GENERATION EXPANSION RESERVE MARGIN	0.0 %	(5) BASE YEAR AVOIDED TRANSMISSION COST	\$/KWH
(2) GENERATOR KW REDUCTION PER CUSTOMER	0.06 KW/CUST	(6) BASE YEAR & DIST. COST ESCALATION RATE	0 \$/KWH
(3) SYSTEM KW LINE LOSS PERCENTAGE	11.0 %	(7) GENERATOR FIXED O & M COST	2.4 %
(4) GENERATION KWH REDUCTION PER CUSTOMER	753 KWH/CUST/YR	(8) GENERATOR FIXED O&M ESCALATION RATE	27.70 \$/KWH/YR
(5) SYSTEM KW LINE LOSS PERCENTAGE	11.0 %	(9) GENERATOR FIXED O&M ESCALATION RATE	2.4 %
(6) GROUP LINE LOSS MULT (DELIVERY VOLTAGE ADJ)	1,000	(10) TRANSMISSION FIXED O & M COST	20.00 \$/KWH/YR
(7) CUSTOMER KWH PROGRAM INCREASE AT METER	0 KWH/CUST/YR	(11) DISTRIBUTION FIXED O & M COST	0.00 \$/KWH/YR
		(12) T&D FIXED O&M ESCALATION RATE	0.0 %
		(13) AVOIDED GEN UNIT VARIABLE O & M COSTS	0.26 CENTS/KWH
		(14) GENERATOR VARIABLE O&M COST ESCALATION RATE	2.4 %
		(15) GENERATOR CAPACITY FACTOR	Annual
		(16) AVOIDED GENERATING UNIT FUEL COST	Annual
		(17) AVOIDED GEN UNIT FUEL ESCALATION RATE	Annual
		(18.1) AVOIDED PURCHASE CAPACITY COST PER KW	0.00 \$/KWH/YR
		(18.2) CAPACITY COST ESCALATION RATE	0.0 %
<u>II. ECONOMIC LIFE, K-FACTOR AND FINANCING RATES</u>		<u>V. NON-FUEL ENERGY AND DEMAND CHARGES</u>	
(1) STUDY PERIOD FOR CONSERVATION PROGRAM	20 YEARS	(1) NON-FUEL COST IN CUSTOMER BILL	5.472 CENTS/KWH
(2) GENERATOR ECONOMIC LIFE	42 YEARS	(2) NON-FUEL COST ESCALATION RATE	1.16 %
(3) T & D ECONOMIC LIFE	35 YEARS	(3) CUSTOMER DEMAND CHARGE PER KW	0.00 \$/KWH/MO
(4) K-FACTOR FOR GENERATION	#N/A	(4) DEMAND CHARGE ESCALATION RATE	0.00 %
(5) K-FACTOR FOR T & D	#N/A	(5.1) CUSTOMER ANNUAL KW BILLING FACTOR ADJUSTMENT	1.000
(6.1) UTILITY DISCOUNT RATE	7.00 %	(5.2) GROUP LINE LOSS ENERGY BILL MULT (DEL VOLT ADJ)	1.000
(6.2) UTILITY DEBT RATE	7.00 %		
(6.3) INSURANCE RATE	0.36 %		
(6.4) RETURN TO CITY	0.00 %		
<u>III. UTILITY AND CUSTOMER COSTS</u>		<u>VI. NATURAL GAS CONVERSION *</u>	
(1) UTILITY NON-RECURRING COST PER CUSTOMER	100.00 \$/CUST	(1) SWITCH TO TURN ON GAS CALCULATIONS	0
(1.1) UTILITY NON-RECURRING COST ESCALATION RATE	2.4 %	(2) KWH TO CF ENERGY CONVERSION FACTOR	0.000
(2) UTILITY RECURRING COST PER CUSTOMER	0.00 \$/CUST/YR	(3) RATIO OF ELECTRIC TO GAS APPLIANCE EFFICIENCY	0.000
(3) UTILITY RECURRING COST ESCALATION RATE	2.4 %	(4) NATURAL GAS NON-FUEL RETAIL RATE	C100CF
(4) CUSTOMER EQUIPMENT COST	0.00 \$/CUST/YR	(5) NATURAL GAS NON-FUEL ESCALATION	0.00 %
(5) CUSTOMER EQUIPMENT ESCALATION RATE	2.4 %		
(6) CUSTOMER O & M COST	0.00 \$/CUST		
(7) CUSTOMER O & M ESCALATION RATE	2.4 %		
(8.1) UTILITY NON-RECURRING REBATE/INCENTIVE	0.00 \$/CUST		
(8.2) UTILITY NON-RECURRING REBATE/INCENTIVE ESC	2.4 %		
(8.3) UTILITY RECURRING REBATE/INCENTIVE	0.00 \$/CUST/YR		
(8.4) UTILITY RECURRING REBATE/INCENTIVE ESC	2.4 %		

ANNUAL INPUT DATA
PROGRAM: RESIDENTIAL ENERGY AUDIT (09R-AUDIT)

YEAR	(1) CUMULATIVE PARTICIPATING CUSTOMERS (NEW/CUST.)	(2) CUMULATIVE TOTAL PARTICIPATING CUSTOMERS	(3) ADJUSTED CUMULATIVE PARTICIPATING CUSTOMERS (REGUR. CUST.)	(4) UTILITY AVERAGE SYSTEM FUEL COSTS (C/KWH)	(5) AVOIDED MARGINAL FUEL COST (C/KWH)	(6) INCREASED MARGINAL FUEL COST (C/KWH)	(7) REPLACEMENT FUEL COST (C/KWH)	(8) PROGRAM KW EFFECTIVENESS FACTOR	(9) PROGRAM KW EFFECTIVENESS FACTOR	(10) NAT GAS COMMODITY & TRANS FUEL COSTS (C/100CF)
2008	1,000	1,000	1,000	2.23	4.49	4.49	0.00	1.0000	1.0000	0.00
2009	1,000	2,000	1,000	2.04	4.54	4.54	0.00	1.0000	1.0000	0.00
2010	1,000	3,000	1,000	2.71	4.43	4.43	0.00	1.0000	1.0000	0.00
2011	1,000	4,000	1,000	1.90	3.97	3.97	3.97	1.0000	1.0000	0.00
2012	1,000	5,000	1,000	1.20	4.54	4.54	4.54	1.0000	1.0000	0.00
2013	1,000	6,000	1,000	1.22	4.69	4.69	4.69	1.0000	1.0000	0.00
2014	1,000	7,000	1,000	1.27	6.07	6.07	6.07	1.0000	1.0000	0.00
2015	2,000	9,000	1,000	1.27	6.26	6.26	6.26	1.0000	1.0000	0.00
2016	2,000	11,000	1,37	6.01	6.01	6.01	6.01	1.0000	1.0000	0.00
2017	2,000	13,000	1,38	7.04	7.04	7.04	7.04	1.0000	1.0000	0.00
2018	2,000	15,000	1,45	6.73	6.73	6.73	6.73	1.0000	1.0000	0.00
2019	2,000	17,000	1,50	6.93	6.93	6.93	6.93	1.0000	1.0000	0.00
2020	2,000	19,000	1,66	7.05	7.05	7.05	7.05	1.0000	1.0000	0.00
2021	2,000	21,000	1,63	7.03	7.03	7.03	7.03	1.0000	1.0000	0.00
2022	3,000	24,000	1,86	7.72	7.72	7.72	7.72	1.0000	1.0000	0.00
2023	3,000	27,000	1,90	7.95	7.95	7.95	7.95	1.0000	1.0000	0.00
2024	3,000	30,000	2.01	8.29	8.29	8.29	8.29	1.0000	1.0000	0.00
2025	3,000	33,000	2.17	8.54	8.54	8.54	8.54	1.0000	1.0000	0.00
2026	3,000	36,000	2.29	8.96	8.96	8.96	8.96	1.0000	1.0000	0.00
2027	3,000	39,000	2.48	9.22	9.22	9.22	9.22	1.0000	1.0000	0.00

SUPPLEMENTAL ANNUAL INPUT DATA

PROGRAM: RESIDENTIAL ENERGY AUDIT (09R-AUDIT)

YEAR	(1) AVOIDED GENERATING UNIT CAPACITY FACTOR (%)	(2) AVOIDED GENERATING UNIT CAPACITY FACTOR (%)	(3) AVOIDED GENERATING UNIT FUEL COST (GJ/RWH)	(4) PURCHASED CAPACITY COSTS (\$/KWH)	(5) INCREASED SUPPLY COSTS (\$000)	<<< OTHER COSTS >>>>>			<<< OTHER BENEFITS >>>>>		
						(6) PARTIC. TEST (\$000)	(7) RIM TEST (\$000)	(8) TRC TEST (\$000)	(9) PARTIC. TEST (\$000)	(10) RIM TEST (\$000)	(11) TRC TEST (\$000)
2008	0.0%	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0	0.0
2009	0.0%	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0	0.0
2010	0.0%	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0	0.0
2011	85.0%	0.43	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0	0.0
2012	85.0%	0.43	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0	0.0
2013	85.0%	0.44	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0	0.0
2014	85.0%	0.45	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0	0.0
2015	85.0%	0.45	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0	0.0
2016	85.0%	0.46	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0	0.0
2017	85.0%	0.47	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0	0.0
2018	85.0%	0.47	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0	0.0
2019	85.0%	0.48	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0	0.0
2020	85.0%	0.48	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0	0.0
2021	85.0%	0.49	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0	0.0
2022	85.0%	0.50	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0	0.0
2023	85.0%	0.51	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0	0.0
2024	85.0%	0.51	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0	0.0
2025	85.0%	0.52	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0	0.0
2026	85.0%	0.53	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0	0.0
2027	85.0%										

GENERATION IN-SERVICE PLANT COST
DRY FORK PROJECT

* OVERNIGHT CONSTRUCTION COSTS (2008 \$s)		3439.84 \$/kW		7.00%							
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	
YEAR	NO. YEARS BEFORE PLANT IN-SERVICE	PLANT COST RATE	CUMULATIVE ESCALATION FACTOR	ANNUAL EXPENDITURE	ANNUAL SPENDING (\$/kW)	CUMULATIVE AVERAGE SPENDING (\$/kW)	CUMULATIVE SPENDING WITH NET CAPITALIZED INTEREST (\$/kW)	ANNUAL NET CAPITALIZED INTEREST (\$/kW)	INCREMENTAL YEAR-END BOOK VALUE (\$/kW)	CUMULATIVE YEAR-END BOOK VALUE (\$/kW)	
2002	-9	2.4%	0.8674	0.0%	0.00	0.00	0.00	0.00	0.00	0.00	
2003	-8	2.4%	0.8882	0.0%	0.00	0.00	0.00	0.00	0.00	0.00	
2004	-7	2.4%	0.9095	0.0%	0.00	0.00	0.00	0.00	0.00	0.00	
2005	-6	2.4%	0.9313	0.0%	0.00	0.00	0.00	0.00	0.00	0.00	
2006	-5	2.4%	0.9537	7.0%	229.63	114.82	114.82	8.04	237.67	237.67	
2007	-4	2.4%	0.9766	15.0%	503.88	481.58	489.61	34.27	538.16	775.83	
2008	-3	2.4%	1.0000	23.0%	791.16	1,129.10	1,171.41	82.00	873.16	1,648.99	
2009	-2	2.4%	1.0240	23.0%	810.15	1,929.76	2,054.06	143.78	953.94	2,602.92	
2010	-1	2.4%	1.0486	23.0%	829.59	2,749.63	3,017.72	211.24	1,040.84	3,643.76	
2011	0	2.4%	1.0737	9.0%	332.41	3,330.63	3,809.97	266.70	599.11	4,242.87	
					100.0%	3496.84					
							746.03			4242.87	

* CONSTRUCTION COSTS AND YEARLY EXPENDITURES INCLUDE ISSUANCE EXPENSES

GENERATION CAPITAL CARRYING CHARGE
DRY FORK PROJECT
PROGRAM: RESIDENTIAL ENERGY AUDIT (09R-AUDIT)

PER-UNIT GEN UNIT COST (2011 \$s), SIZE OF DSM AVOIDED GEN CAPACITY IN-SERVICE AVOIDED GEN UNIT COST (\$000)	BOOK LIFE (YEARS)						(10)	(11)	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
MID-YEAR RATE-BASE	DEBT PRINCIPAL PAYMENT	DEBT INTEREST PAYMENT	TOTAL DEBT PAYMENT	RETURN TO GVT PAYMENT	INSURANCE	TOTAL FIXED CHARGES	PRESENT WORTH FIXED CHARGES	CUMULATIVE PW FIXED CHARGES	CAPITAL CARRYING CHARGE
2011	243	1	17	18	0	1	19	19	0.0779
2012	243	1	17	18	0	1	18	37	0.0779
2013	243	1	17	18	0	1	17	53	0.0779
2014	243	1	17	18	0	1	15	69	0.0779
2015	243	1	17	18	0	1	14	83	0.0779
2016	243	1	17	18	0	1	14	97	0.0779
2017	243	2	16	18	0	1	13	109	0.0779
2018	243	2	16	18	0	1	12	121	0.0779
2019	243	2	16	18	0	1	11	132	0.0779
2020	243	2	16	18	0	1	10	142	0.0779
2021	243	2	16	18	0	1	10	152	0.0779
2022	243	2	16	18	0	1	9	161	0.0779
2023	243	2	16	18	0	1	8	169	0.0779
2024	243	3	16	18	0	1	8	177	0.0779
2025	243	3	15	18	0	1	7	185	0.0779
2026	243	3	15	18	0	1	7	192	0.0779
2027	243	3	15	18	0	1	6	198	0.0779
2028	243	3	15	18	0	1	6	204	0.0779
2029	243	4	15	18	0	1	6	210	0.0779
2030	243	4	14	18	0	1	5	215	0.0779
2031	243	4	14	18	0	1	5	220	0.0779
2032	243	4	14	18	0	1	5	224	0.0779
2033	243	5	13	18	0	1	4	229	0.0779
2034	243	5	13	18	0	1	4	233	0.0779
2035	243	5	13	18	0	1	4	236	0.0779
2036	243	6	12	18	0	1	3	240	0.0779
2037	243	6	12	18	0	1	3	243	0.0779
2038	243	7	12	18	0	1	3	246	0.0779
2039	243	7	11	18	0	1	3	249	0.0779
2040	243							252	

AVOIDED GENERATION UNIT BENEFITS
PROGRAM: RESIDENTIAL ENERGY AUDIT (99R-AUDIT)

Year	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
									57 KW \$243
									IN-SERVICE COSTS OF AVOIDED GEN. UNIT (000) =
									SIZE OF AVOIDED GENERATION UNIT =
2008	0	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0	0
2011	19	2	427	1	2	17	0	0	7
2012	19	2	427	1	2	19	0	0	4
2013	19	2	427	1	2	20	0	0	4
2014	19	2	427	1	2	26	0	0	(2)
2015	19	2	427	1	2	27	0	0	(3)
2016	19	2	427	1	2	26	0	0	(1)
2017	19	2	427	1	2	30	0	0	(6)
2018	19	2	427	1	2	29	0	0	(4)
2019	19	2	427	1	2	30	0	0	(5)
2020	19	2	427	1	2	30	0	0	(6)
2021	19	2	427	1	2	30	0	0	(5)
2022	19	2	427	2	2	33	0	0	(8)
2023	19	2	427	2	2	34	0	0	(9)
2024	19	2	427	2	2	35	0	0	(10)
2025	19	2	427	2	2	36	0	0	(11)
2026	19	2	427	2	2	38	0	0	(13)
2027	19	2	427	2	2	39	0	0	(14)
NOMINAL	322	35		24	35	499	0	(83)	
NPV	162	17		12	17	233	0	(26)	

AVOIDED T & D AND PROGRAM FUEL BENEFITS
PROGRAM: RESIDENTIAL ENERGY AUDIT (09R-AUDIT)

Year	AVOIDED TRANS. CAPACITY COST (\$000)	AVOIDED TRANS. O&M COST (\$000)	EFFECTIVE TOTAL AVOIDED TRANS. COST (\$000)	AVOIDED DISTRI. CAPACITY COST (\$000)	AVOIDED DISTRI. O&M COST (\$000)	EFFECTIVE TOTAL AVOIDED DISTRI. COST (\$000)	EFFECTIVE NET PROGRAM FUEL SAVINGS (\$000)
2008	0	1	1	0	0	0	17
2009	0	1	1	0	0	0	34
2010	0	1	1	0	0	0	33
2011	0	1	1	0	0	0	30
2012	0	1	1	0	0	0	34
2013	0	1	1	0	0	0	35
2014	0	1	1	0	0	0	46
2015	0	1	1	0	0	0	47
2016	0	1	1	0	0	0	45
2017	0	1	1	0	0	0	53
2018	0	1	1	0	0	0	51
2019	0	1	1	0	0	0	52
2020	0	1	1	0	0	0	53
2021	0	1	1	0	0	0	53
2022	0	1	1	0	0	0	58
2023	0	1	1	0	0	0	60
2024	0	1	1	0	0	0	62
2025	0	1	1	0	0	0	64
2026	0	1	1	0	0	0	67
2027	0	1	1	0	0	0	69
NOMINAL	0	23	23	0	0	0	965
NPV	0	13	13	0	0	0	489

WORKSHEET: FUEL SAVINGS WORKSHEET
PROGRAM: RESIDENTIAL ENERGY AUDIT (09R-AUDIT)

(1)	(2)	(3)	(4)	(5)	(6)	(7)
YEAR	ON-PEAK KWH GENERATION REDUCTION (000)	AVOIDED ON-PEAK MARGINAL FUEL COST (\$000)	OFF-PEAK KWH GENERATION INCREASE (000)	INCREASED OFF-PEAK MARGINAL FUEL COST (\$000)	NET AVOIDED PROGRAM FUEL SAVINGS (\$000)	EFFECTIVE NET AVOIDED FUEL SAVINGS (\$000)
2008	376	17	0	0	17	17
2009	753	34	0	0	34	34
2010	753	33	0	0	33	33
2011	753	30	0	0	30	30
2012	753	34	0	0	34	34
2013	753	35	0	0	35	35
2014	753	46	0	0	46	46
2015	753	47	0	0	47	47
2016	753	45	0	0	45	45
2017	753	53	0	0	53	53
2018	753	51	0	0	51	51
2019	753	52	0	0	52	52
2020	753	53	0	0	53	53
2021	753	53	0	0	53	53
2022	753	58	0	0	58	58
2023	753	60	0	0	60	60
2024	753	62	0	0	62	62
2025	753	64	0	0	64	64
2026	753	67	0	0	67	67
2027	753	69	0	0	69	69
NOMINAL	14,680	965	0	0	965	965
NPV		489	0	0	489	489

WORKSHEET: UTILITY AND PARTICIPANT DSM COSTS

PROGRAM: RESIDENTIAL ENERGY AUDIT (09R-AUDIT)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
YEAR	UTILITY NONREC. COSTS (\$000)	UTILITY RECUR. COSTS (\$000)	TOTAL UTILITY PROG. COSTS (\$000)	UTILITY NONREC. REBATE/INCENT. (\$000)	UTILITY REBATE/INCENT. (\$000)	TOTAL UTILITY REBATE/INCENT. (\$000)	PARTIC. CUST. EQUIP. COSTS (\$000)	PARTIC. CUST. O&M COSTS (\$000)	TOTAL PARTIC. CUST. O&M COSTS (\$000)
2008	100	0	100	0	0	0	0	190	0
2009	0	0	0	0	0	0	0	0	190
2010	0	0	0	0	0	0	0	0	0
2011	0	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0
2015	118	0	118	0	0	0	0	224	0
2016	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0
2022	139	0	139	0	0	0	0	265	0
2023	0	0	0	0	0	0	0	0	265
2024	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0
NOMINAL	357	0	357	0	0	0	679	0	679
NPV	228	0	228	0	0	0	432	0	432

WORKSHEET: REVENUE LOSS/GAIN
PROGRAM: RESIDENTIAL ENERGY AUDIT (99R-AUDIT)

(1) YEAR	(2) CUSTOMER BILL KWH REDUCTION (\$000)	(3) CUST. BILL REDUCT. FUEL PORTION (\$000)	(4) CUST. BILL REDUCT. NONFUEL PORTION (\$000)	(5) TOTAL ELECTRIC REVENUE REDUCT. (\$000)	(6) EFFECTIVE ELECTRIC REVENUE REDUCT. (\$000)	(7) CUSTOMER BILL KWH INCREASE (\$000)	(8) CUST. BILL INCR. FUEL PORTION (\$000)	(9) CUST. BILL INCR. NONFUEL PORTION (\$000)	(10) TOTAL ELECTRIC REVENUE INCR. (\$000)	(11) EFFECTIVE ELECTRIC REVENUE INCR. (\$000)	(12) EFFECTIVE NAT GAS REVENUE INCR. (\$000)
2008	335	8	18	27	27	27	0	0	0	0	0
2009	670	15	37	52	52	52	0	0	0	0	0
2010	670	20	38	58	58	58	0	0	0	0	0
2011	670	14	38	52	52	52	0	0	0	0	0
2012	670	9	38	47	47	47	0	0	0	0	0
2013	670	9	39	48	48	48	0	0	0	0	0
2014	670	10	39	49	49	49	0	0	0	0	0
2015	670	10	40	49	49	49	0	0	0	0	0
2016	670	10	40	51	51	51	0	0	0	0	0
2017	670	10	41	51	51	51	0	0	0	0	0
2018	670	11	41	52	52	52	0	0	0	0	0
2019	670	11	42	53	53	53	0	0	0	0	0
2020	670	12	42	55	55	55	0	0	0	0	0
2021	670	12	43	55	55	55	0	0	0	0	0
2022	670	14	43	57	57	57	0	0	0	0	0
2023	670	14	44	58	58	58	0	0	0	0	0
2024	670	15	44	59	59	59	0	0	0	0	0
2025	670	16	45	61	61	61	0	0	0	0	0
2026	670	17	45	62	62	62	0	0	0	0	0
2027	670	19	46	64	64	64	0	0	0	0	0
NOMINAL	13,065	259	802		1,061		0	0	0	0	0
NPV		142	435		577		0	0	0	0	0

UTILITY COST TEST
PROGRAM: RESIDENTIAL ENERGY AUDIT (09R-AUDIT)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
YEAR	INCREASED SUPPLY COSTS (\$'000)	UTILITY PROGRAM COSTS (\$'000)	REBATES/ INCENT. (\$'000)	OTHER COSTS (\$'000)	TOTAL COSTS (\$'000)	AVOIDED GEN UNIT BENEFITS (\$'000)	AVOIDED T & D BENEFITS (\$'000)	PROGRAM FUEL SAVINGS (\$'000)	OTHER BENEFITS (\$'000)	TOTAL BENEFITS (\$'000)	NET BENEFITS (\$'000)	CUMULATIVE DISCOUNTED NET BENEFITS (\$'000)
2008	0	100	0	0	100	0	1	17	0	18	(82)	(82)
2009	0	0	0	0	0	0	1	34	0	35	35	(49)
2010	0	0	0	0	0	0	1	33	0	34	34	(19)
2011	0	0	0	0	0	0	1	30	0	38	38	12
2012	0	0	0	0	0	0	1	34	0	40	40	42
2013	0	0	0	0	0	0	1	35	0	40	40	71
2014	0	0	0	0	0	0	1	46	0	45	45	101
2015	0	118	0	0	118	(2)	1	47	0	46	(72)	56
2016	0	0	0	0	0	(3)	1	45	0	45	45	82
2017	0	0	0	0	0	(1)	1	45	0	45	45	82
2018	0	0	0	0	0	(6)	1	53	0	48	48	108
2019	0	0	0	0	0	(4)	1	51	0	47	47	132
2020	0	0	0	0	0	(5)	1	52	0	48	48	155
2021	0	0	0	0	0	(6)	1	53	0	49	49	177
2022	0	139	0	0	139	(5)	1	53	0	49	49	197
2023	0	0	0	0	0	(8)	1	58	0	51	(88)	163
2024	0	0	0	0	0	(9)	1	60	0	52	52	182
2025	0	0	0	0	0	(10)	1	62	0	53	53	200
2026	0	0	0	0	0	(11)	1	64	0	54	54	217
2027	0	0	0	0	0	(13)	1	67	0	56	56	233
NOMINAL	0	357	0	0	357	(83)	23	965	0	905	548	
NPV	0	228	0	0	228	(26)	13	489	0	477	249	

Benefit/Cost Ratio [col (11) / col (6)]:
 Discount Rate:

7.00%
 2.09

TOTAL RESOURCE COST TEST
PROGRAM: RESIDENTIAL ENERGY AUDIT (OSR-AUDIT)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
YEAR	INCREASED SUPPLY COSTS (\$'000)	UTILITY PROGRAM COSTS (\$'000)	PARTIC. PROGRAM COSTS (\$'000)	OTHER COSTS (\$'000)	TOTAL COSTS (\$'000)	AVOIDED GEN UNIT BENEFITS (\$'000)	AVOIDED T & D BENEFITS (\$'000)	PROGRAM FUEL SAVINGS (\$'000)	OTHER BENEFITS (\$'000)	TOTAL BENEFITS (\$'000)	NET BENEFITS (\$'000)	CUMULATIVE DISCOUNTED NET BENEFITS (\$'000)
2008	0	100	190	0	290	0	1	17	0	18	(272)	(272)
2009	0	0	0	0	0	0	1	34	0	35	35	(239)
2010	0	0	0	0	0	0	1	33	0	34	34	(209)
2011	0	0	0	0	0	0	1	30	0	38	38	(176)
2012	0	0	0	0	0	0	1	34	0	40	40	(148)
2013	0	0	0	0	0	0	1	35	0	40	40	(119)
2014	0	0	0	0	0	0	1	46	0	45	45	(89)
2015	0	118	224	0	342	(3)	1	47	0	46	(297)	(274)
2016	0	0	0	0	0	(1)	1	45	0	45	45	(248)
2017	0	0	0	0	0	(6)	1	53	0	48	48	(221)
2018	0	0	0	0	0	(4)	1	51	0	47	47	(197)
2019	0	0	0	0	0	(5)	1	52	0	48	48	(174)
2020	0	0	0	0	0	(6)	1	53	0	49	49	(153)
2021	0	0	0	0	0	(5)	1	53	0	49	49	(133)
2022	0	139	265	0	404	(8)	1	58	0	51	(353)	(270)
2023	0	0	0	0	0	(9)	1	60	0	52	52	(251)
2024	0	0	0	0	0	(10)	1	62	0	53	53	(233)
2025	0	0	0	0	0	(11)	1	64	0	54	54	(215)
2026	0	0	0	0	0	(13)	1	67	0	56	56	(199)
2027	0	0	0	0	0	(14)	1	69	0	57	57	(183)
NOMINAL	0	357	679	0	1,037	(83)	23	565	0	905	(131)	

Benefit/Cost Ratio [col (11) / col (6)]: 0.72
 Discount Rate: 7.00%

RATE IMPACT TEST
PROGRAM: RESIDENTIAL ENERGY AUDIT (09R-AUDIT)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
YEAR	INCREASED SUPPLY COSTS (\$'000)	UTILITY PROGRAM COSTS (\$'000)	REBATES/ INCENT. (\$'000)	ELECTRIC REVENUE LOSSES (\$'000)	OTHER COSTS (\$'000)	TOTAL COSTS (\$'000)	AVOIDED GEN UNIT & FUEL BENEFITS (\$'000)	AVOIDED T & D BENEFITS (\$'000)	ELECTRIC GAINS (\$'000)	NAT GAS REVENUE GAINS (\$'000)	OTHER BENEFITS (\$'000)	TOTAL BENEFITS (\$'000)	BENEFITS TO ALL CUSTOMERS (\$'000)	CUMULATIVE DISCOUNTED NET BENEFIT (\$'000)
2008	0	100	0	27	0	127	17	1	0	0	0	18	(109)	(109)
2009	0	0	0	52	0	52	34	1	0	0	0	35	(117)	(125)
2010	0	0	0	58	0	58	33	1	0	0	0	34	(23)	(145)
2011	0	0	0	52	0	52	37	1	0	0	0	38	(14)	(157)
2012	0	0	0	47	0	47	39	1	0	0	0	40	(8)	(163)
2013	0	0	0	48	0	48	39	1	0	0	0	40	(8)	(168)
2014	0	0	0	49	0	49	44	1	0	0	0	45	(4)	(171)
2015	0	118	0	49	0	167	44	1	0	0	0	46	(122)	(247)
2016	0	0	0	51	0	51	44	1	0	0	0	45	(6)	(250)
2017	0	0	0	51	0	51	47	1	0	0	0	48	(3)	(252)
2018	0	0	0	52	0	52	46	1	0	0	0	47	(5)	(254)
2019	0	0	0	53	0	53	47	1	0	0	0	48	(5)	(256)
2020	0	0	0	55	0	55	48	1	0	0	0	49	(6)	(259)
2021	0	0	0	55	0	55	48	1	0	0	0	49	(6)	(261)
2022	0	139	0	57	0	196	50	1	0	0	0	51	(145)	(318)
2023	0	0	0	58	0	58	51	1	0	0	0	52	(6)	(320)
2024	0	0	0	59	0	59	52	1	0	0	0	53	(6)	(322)
2025	0	0	0	61	0	61	53	1	0	0	0	54	(7)	(324)
2026	0	0	0	62	0	62	55	1	0	0	0	56	(7)	(326)
2027	0	0	0	64	0	64	56	1	0	0	0	57	(8)	(328)
NOMINAL	0	357	0	1,061	0	1,418	882	23	0	0	0	905	(513)	
NPV	0	228	0	577	0	805	464	13	0	0	0	477	(328)	
Benefit / Cost Ratio [col (13) / col (7)]				7.00%										
Discount rate:				0.59										

PARTICIPANT COSTS AND BENEFITS
PROGRAM: RESIDENTIAL ENERGY AUDIT (09R-AUDIT)

YEAR	(1) SAVINGS IN PARTICIPANT ELEC. BILL (\$000)	(2) PARTIC. CREDITS (\$000)	(3) PARTIC. TAX CREDITS (\$000)	(4) UTILITY REBATES/ INCENT. (\$000)	(5) OTHER PARTIC. BENEFITS (\$000)	(6) TOTAL PARTIC. BENEFITS (\$000)	(7) INCREASE IN PARTICIPANT GAS BILL (\$000)	(8) PARTIC. EQUIP. COSTS (\$000)	(9) PARTIC. O & M COSTS (\$000)	(10) OTHER PARTIC. COSTS (\$000)	(11) TOTAL COSTS (\$000)	(12) NET BENEFITS (\$000)	(13) CUMULATIVE DISCOUNTED NET BENEFITS (\$000)
2008	27	0	0	27	0	190	0	0	0	0	190	(163)	(163)
2009	52	0	0	52	0	0	0	0	0	0	0	52	(114)
2010	58	0	0	58	0	0	0	0	0	0	0	58	(64)
2011	52	0	0	52	0	0	0	0	0	0	0	52	(21)
2012	47	0	0	47	0	0	0	0	0	0	0	47	15
2013	48	0	0	48	0	0	0	0	0	0	0	48	49
2014	49	0	0	49	0	0	0	0	0	0	0	49	82
2015	49	0	0	49	0	0	0	224	0	0	224	(175)	(27)
2016	51	0	0	51	0	0	0	0	0	0	0	51	2
2017	51	0	0	51	0	0	0	0	0	0	0	51	30
2018	52	0	0	52	0	0	0	0	0	0	0	52	57
2019	53	0	0	53	0	0	0	0	0	0	0	53	82
2020	55	0	0	55	0	0	0	0	0	0	0	55	106
2021	55	0	0	55	0	0	0	0	0	0	0	55	129
2022	57	0	0	57	0	0	265	0	0	0	265	(208)	48
2023	58	0	0	58	0	0	0	0	0	0	0	58	69
2024	59	0	0	59	0	0	0	0	0	0	0	59	89
2025	61	0	0	61	0	0	0	0	0	0	0	61	109
2026	62	0	0	62	0	0	0	0	0	0	0	62	127
2027	64	0	0	64	0	0	0	0	0	0	0	64	145
NOMINAL	1,061	0	0	0	1,061	0	679	0	0	0	679	382	
NPV	577	0	0	0	577	0	432	0	0	432	0	145	
In-service year of generation unit:		2011		Discount rate:		7.00%							

INPUT DATA
PROGRAM: COMMERCIAL ENERGY AUDIT (14C-AUDIT)

<u>I. PROGRAM DEMAND SAVINGS AND LINE LOSSES</u>		<u>IV. AVOIDED GENERATOR, TRANS. AND DIST. COSTS</u>	
(1) CUSTOMER NON-COINCIDENT KW REDUCTION AT METER	0.33 KW/CUST	(1) BASE YEAR	2008
(1.1) CUSTOMER KW REDUCTION PEAK COINCIDENCE FACTOR	0.400	(2) IN-SERVICE YEAR FOR AVOIDED GENERATING UNIT	2011
(1.2) CUSTOMER KWH REDUCTION AT METER	1,660 KWH/CUST/YR	(3) IN-SERVICE YEAR FOR AVOIDED T & D	2008
(1.3) CUSTOMER COINCIDENT KW REDUCTION AT THE METER	0.13 KW/CUST	(4) BASE YEAR AVOIDED GENERATING UNIT COST	3,440 \$/KWH
(1.4) GENERATION EXPANSION RESERVE MARGIN	0.0 %	(5) BASE YEAR AVOIDED TRANSMISSION COST	0 \$/KWH
(2) GENERATOR KW REDUCTION PER CUSTOMER	0.15 KW/CUST	(6) BASE YEAR DISTRIBUTION COST	0 \$/KWH
(3) SYSTEM KW/LINE LOSS PERCENTAGE	11.0 %	(7) GEN. TRAN. & DIST. COST ESCALATION RATE	2.4 %
(4) GENERATION KWH REDUCTION PER CUSTOMER	1,854 KWH/CUST/YR	(8) GENERATOR FIXED O & M COST	27.70 \$/KWH/YR
(5) SYSTEM KW/H LINE LOSS PERCENTAGE	11.0 %	(9) GENERATOR FIXED O&M ESCALATION RATE	2.4 %
(6) GROUP LINE LOSS MULIT (DELIVERY VOLTAGE ADJ)	1,000	(10) TRANSMISSION FIXED O & M COST	20.00 \$/KWH/YR
(7) CUSTOMER KWH PROGRAM INCREASE AT METER	0 KWH/CUST/YR	(11) DISTRIBUTION FIXED O & M COST	0.00 \$/KWH/YR
		(12) T&D FIXED O&M ESCALATION RATE	0.0 %
		(13) AVOIDED GEN UNIT VARIABLE O & M COSTS	0.26 CENTS/KWH
		(14) GENERATOR VARIABLE O&M COST ESCALATION RATE	2.44 %
		(15) GENERATOR CAPACITY FACTOR	Annual
		(16) AVOIDED GENERATING UNIT FUEL COST	Annual
		(17) AVOIDED GEN UNIT FUEL ESCALATION RATE	Annual
		(18.1) AVOIDED PURCHASE CAPACITY COST PER KW	0.00 \$/KWH/YR
		(18.2) CAPACITY COST ESCALATION RATE	0.0 %
<u>II. ECONOMIC LIFE, K-FACTOR AND FINANCING RATES</u>		<u>V. NON-FUEL ENERGY AND DEMAND CHARGES</u>	
(1) STUDY PERIOD FOR CONSERVATION PROGRAM	20 YEARS	(1) NON-FUEL COST IN CUSTOMER BILL	6,276 CENTS/KWH
(2) GENERATOR ECONOMIC LIFE	42 YEARS	(2) NON-FUEL COST ESCALATION RATE	1.57 %
(3) T & D ECONOMIC LIFE	35 YEARS	(3) CUSTOMER DEMAND CHARGE PER KW	0.00 \$/KWH/MO
(4) K-FACTOR FOR GENERATION	#N/A	(4) DEMAND CHARGE ESCALATION RATE	0.00 %
(5) K-FACTOR FOR T & D	#N/A	(5.1) CUSTOMER ANNUAL KW BILLING FACTOR ADJUSTMENT	1.000
(6.1) UTILITY DISCOUNT RATE	7.00 %	(5.2) GROUP LINE LOSS ENERGY BILL MULT (DEL.VOLT.ADJ)	1.000
(6.2) UTILITY DEBT RATE	7.00 %		
(6.3) INSURANCE RATE	0.36 %		
(6.4) RETURN TO CITY	0.00 %		
<u>III. UTILITY AND CUSTOMER COSTS</u>		<u>VI. NATURAL GAS CONVERSION *</u>	
(1) UTILITY NON-RECURRING COST PER CUSTOMER	150.00 \$/CUST	(1) SWITCH TO TURN ON GAS CALCULATIONS	0
(1.1) UTILITY NON-RECURRING COST ESCALATION RATE	2.4 %	(2) KWH TO CF ENERGY CONVERSION FACTOR	0.000
(2) UTILITY RECURRING COST PER CUSTOMER	0.00 \$/CUST/YR	(3) RATIO OF ELECTRIC TO GAS APPLIANCE EFFICIENCY	0.000
(3) UTILITY RECURRING COST ESCALATION RATE	2.4 %	(4) NATURAL GAS NON-FUEL RETAIL RATE	0.000 C/100CF
(4) CUSTOMER EQUIPMENT COST	420.00 \$/CUST	(5) NATURAL GAS NON-FUEL ESCALATION	0.00 %
(5) CUSTOMER O & M COST	0.00 \$/CUST/YR		
(6) CUSTOMER O & M ESCALATION RATE	2.4 %		
(7) UTILITY NON-RECURRING REBATE/INCENTIVE	0.00 \$/CUST		
(8.1) UTILITY NON-RECURRING REBATE/INCENTIVE ESC	2.4 %		
(8.2) UTILITY RECURRING REBATE/INCENTIVE ESC	0.00 \$/CUST/YR		
(8.3) UTILITY RECURRING REBATE/INCENTIVE	2.4 %		
(8.4) UTILITY RECURRING REBATE/INCENTIVE ESC	2.4 %		

ANNUAL INPUT DATA
PROGRAM: COMMERCIAL ENERGY AUDIT (14C-AUDIT)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
YEAR	CUMULATIVE PARTICIPATING CUSTOMERS (NEW CUST.)	ADJUSTED CUMULATIVE PARTICIPATING CUSTOMERS (RECUR. CUST.)	UTILITY AVERAGE SYSTEM FUEL COSTS (CKW/H)	AVOIDED MARGINAL FUEL COST (CKW/H)	INCREASED MARGINAL FUEL COST (CKW/H)	REPLACEMENT FUEL COST (GKWH)	PROGRAM KW EFFECTIVENESS FACTOR	PROGRAM KW EFFECTIVENESS FACTOR	NAT GAS COMMODITY & TRANS FUEL COSTS (G100CF)
2008	1,000	1,000	2.23	4.49	4.49	0.00	1.0000	1.0000	0.00
2009	1,000	1,000	2.04	4.54	4.54	0.00	1.0000	1.0000	0.00
2010	1,000	1,000	2.71	4.43	4.43	0.00	1.0000	1.0000	0.00
2011	1,000	1,90	3.97	3.97	3.97	3.97	1.0000	1.0000	0.00
2012	1,000	1,000	1.20	4.54	4.54	4.54	1.0000	1.0000	0.00
2013	2,000	1,000	1.22	4.69	4.69	4.69	1.0000	1.0000	0.00
2014	2,000	1,000	1.27	6.07	6.07	6.07	1.0000	1.0000	0.00
2015	2,000	1,000	1.27	6.26	6.26	6.26	1.0000	1.0000	0.00
2016	2,000	1,000	1.37	6.01	6.01	6.01	1.0000	1.0000	0.00
2017	2,000	1,000	1.38	7.04	7.04	7.04	1.0000	1.0000	0.00
2018	3,000	1,000	1.45	6.73	6.73	6.73	1.0000	1.0000	0.00
2019	3,000	1,000	1.50	6.93	6.93	6.93	1.0000	1.0000	0.00
2020	3,000	1,000	1.66	7.05	7.05	7.05	1.0000	1.0000	0.00
2021	3,000	1,000	1.63	7.03	7.03	7.03	1.0000	1.0000	0.00
2022	3,000	1,000	1.86	7.72	7.72	7.72	1.0000	1.0000	0.00
2023	4,000	1,000	1.90	7.95	7.95	7.95	1.0000	1.0000	0.00
2024	4,000	1,000	2.01	8.29	8.29	8.29	1.0000	1.0000	0.00
2025	4,000	1,000	2.17	8.54	8.54	8.54	1.0000	1.0000	0.00
2026	4,000	1,000	2.29	8.96	8.96	8.96	1.0000	1.0000	0.00
2027	4,000	1,000	2.48	9.22	9.22	9.22	1.0000	1.0000	0.00

SUPPLEMENTAL ANNUAL INPUT DATA
PROGRAM: COMMERCIAL ENERGY AUDIT (14C-AUDIT)

YEAR	(1) AVOIDED GENERATING UNIT CAPACITY FACTOR (%)	(2) AVOIDED GENERATING UNIT CAPACITY FACTOR (%)	(3) AVOIDED GENERATING UNIT FUEL COST (\$/KWH)	(4) PURCHASED CAPACITY COSTS (\$/KWHYR)	(5) INCREASED SUPPLY COSTS (\$/000)	<<< OTHER COSTS >>>>			<<< OTHER BENEFITS >>>>>		
						(6) PARTIC. TEST (\$/000)	(7) RIM TEST (\$/000)	(8) TRC TEST (\$/000)	(9) PARTIC. TEST (\$/000)	(10) RIM TEST (\$/000)	(11) TRC TEST (\$/000)
2008	0.0%	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2009	0.0%	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2010	0.0%	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2011	85.0%	0.43	0.43	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2012	85.0%	0.43	0.43	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2013	85.0%	0.44	0.44	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2014	85.0%	0.45	0.45	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2015	85.0%	0.45	0.45	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2016	85.0%	0.46	0.46	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2017	85.0%	0.47	0.47	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2018	85.0%	0.47	0.47	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2019	85.0%	0.48	0.48	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2020	85.0%	0.48	0.48	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2021	85.0%	0.49	0.49	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2022	85.0%	0.50	0.50	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2023	85.0%	0.51	0.51	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2024	85.0%	0.51	0.51	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2025	85.0%	0.52	0.52	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2026	85.0%	0.53	0.53	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2027	85.0%	0.53	0.53	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0

GENERATION IN-SERVICE PLANT COST
DRY FORK PROJECT

* OVERNIGHT CONSTRUCTION COSTS (2008 \$\$)
 CAPITALIZED INTEREST RATE

3439.84 \$/kW
 7.00%

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
YEAR	NO. YEARS BEFORE PLANT IN-SERVICE	PLANT COST ESCALATION RATE	CUMULATIVE ESCALATION FACTOR	ANNUAL EXPENDITURE	ANNUAL SPENDING (\$/kW)	CUMULATIVE AVERAGE SPENDING (\$/kW)	CUMULATIVE SPENDING WITH NET CAPITALIZED INTEREST (\$/kW)	ANNUAL NET CAPITALIZED INTEREST (\$/kW)	INCREMENTAL YEAR-END BOOK VALUE (\$/kW)	CUMULATIVE YEAR-END BOOK VALUE (\$/kW)
2002	-9	2.4%	0.8674	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2003	-8	2.4%	0.8882	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2004	-7	2.4%	0.9095	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2005	-6	2.4%	0.9313	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2006	-5	2.4%	0.9537	7.0%	229.63	114.82	114.82	8.04	237.67	237.67
2007	-4	2.4%	0.9766	15.0%	503.88	481.58	481.58	34.27	538.16	775.83
2008	-3	2.4%	1.0000	23.0%	791.16	1,129.10	1,129.10	1,171.41	82.00	873.16
2009	-2	2.4%	1.0240	23.0%	810.15	1,928.76	1,928.76	2,054.06	953.94	1,648.99
2010	-1	2.4%	1.0486	23.0%	829.59	2,749.63	2,749.63	3,017.72	211.24	2,602.92
2011	0	2.4%	1.0737	9.0%	332.41	3,330.63	3,330.63	3,869.97	266.70	3,643.76
					100.0%	3496.84			599.11	4,242.87
							746.03			746.03

* CONSTRUCTION COSTS AND YEARLY EXPENDITURES INCLUDE ISSUANCE EXPENSES

GENERATION CAPITAL CARRYING CHARGE
DRY FORK PROJECT
PROGRAM: COMMERCIAL ENERGY AUDIT (14C-AUDIT)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	BOOK LIFE (YEARS)
											DEBT PAYMENT
											INSURANCE RATE
											RETURN TO GOVERNMENT
PER-UNIT GEN UNIT COST (2011 \$s)											
SIZE OF DSM AVOIDED GEN CAPACITY											
IN-SERVICE AVOIDED GEN UNIT COST (\$000)											
4,242.87	\$/kW										
148	KW										
\$629											
2011	629	3	44	47	0	2	49	49	49	49	0.0779
2012	629	3	44	47	0	2	49	46	95	95	0.0779
2013	629	3	44	47	0	2	49	43	138	138	0.0779
2014	629	3	43	47	0	2	49	40	178	178	0.0779
2015	629	4	43	47	0	2	49	37	215	215	0.0779
2016	629	4	43	47	0	2	49	35	250	250	0.0779
2017	629	4	43	47	0	2	49	33	283	283	0.0779
2018	629	4	42	47	0	2	49	31	313	313	0.0779
2019	629	5	42	47	0	2	49	29	342	342	0.0779
2020	629	5	42	47	0	2	49	27	369	369	0.0779
2021	629	5	41	47	0	2	49	25	394	394	0.0779
2022	629	6	41	47	0	2	49	23	417	417	0.0779
2023	629	6	41	47	0	2	49	22	439	439	0.0779
2024	629	7	40	47	0	2	49	20	459	459	0.0779
2025	629	7	40	47	0	2	49	19	478	478	0.0779
2026	629	8	39	47	0	2	49	18	496	496	0.0779
2027	629	8	39	47	0	2	49	17	512	512	0.0779
2028	629	9	38	47	0	2	49	16	528	528	0.0779
2029	629	9	38	47	0	2	49	15	542	542	0.0779
2030	629	10	37	47	0	2	49	14	556	556	0.0779
2031	629	11	36	47	0	2	49	13	569	569	0.0779
2032	629	11	35	47	0	2	49	12	580	580	0.0779
2033	629	12	35	47	0	2	49	11	592	592	0.0779
2034	629	13	34	47	0	2	49	10	602	602	0.0779
2035	629	14	33	47	0	2	49	10	612	612	0.0779
2036	629	15	32	47	0	2	49	9	621	621	0.0779
2037	629	16	31	47	0	2	49	8	629	629	0.0779
2038	629	17	30	47	0	2	49	8	637	637	0.0779
2039	629	18	29	47	0	2	49	7	644	644	0.0779
2040	629	19	27	47	0	2	49	7	651	651	0.0779

AVOIDED GENERATION UNIT BENEFITS
PROGRAM: COMMERCIAL ENERGY AUDIT (14C-AUDIT)

Year	SIZE OF AVOIDED GENERATION UNIT = IN-SERVICE COSTS OF AVOIDED GEN. UNIT (000) =					148 kW \$629		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	AVOIDED GEN. UNIT CAPACITY COST (\$000)	AVOIDED GEN. UNIT FIXED O&M COST (\$000)	AVOIDED GEN. UNIT ANNUAL KWH GEN (000)	AVOIDED GEN. UNIT VARIABLE O&M COST (\$000)	AVOIDED GEN. UNIT FUEL COST (\$000)	LESS REPLACEMENT FUEL COST (\$000)	AVOIDED PURCHASED CAPACITY COSTS (\$000)	EFFECTIVE NET AVOIDED GEN. UNIT BENEFITS (\$000)
2008	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0
2011	49	4	1,104	3	5	44	0	17
2012	49	5	1,104	3	5	50	0	11
2013	49	5	1,104	3	5	52	0	10
2014	49	5	1,104	3	5	67	0	(5)
2015	49	5	1,104	3	5	69	0	(7)
2016	49	5	1,104	3	5	66	0	(4)
2017	49	5	1,104	3	5	78	0	(5)
2018	49	5	1,104	4	5	74	0	(11)
2019	49	5	1,104	4	5	77	0	(13)
2020	49	5	1,104	4	5	78	0	(14)
2021	49	6	1,104	4	5	78	0	(21)
2022	49	6	1,104	4	6	85	0	(23)
2023	49	6	1,104	4	6	88	0	(27)
2024	49	6	1,104	4	6	92	0	(29)
2025	49	6	1,104	4	6	94	0	(33)
2026	49	6	1,104	4	6	99	0	(36)
2027	49	6	1,104	4	6	102	0	(37)
NOMINAL	834	91	63	90	1,292	0	(24)	
NPV	418	44	30	44	604	0	(67)	

AVOIDED T & D AND PROGRAM FUEL BENEFITS
PROGRAM: COMMERCIAL ENERGY AUDIT (14C-AUDIT)

Year	(1) AVOIDED TRANS. CAPACITY COST (\$000)	(2) AVOIDED TRANS. O&M COST (\$000)	(3) EFFECTIVE TOTAL AVOIDED TRANS. COST (\$000)	(4) AVOIDED DISTRIB. CAPACITY COST (\$000)	(5) AVOIDED DISTRIB. O&M COST (\$000)	(6) EFFECTIVE TOTAL AVOIDED DISTRIB. COST (\$000)	(7) EFFECTIVE TOTAL AVOIDED DISTRIB. COST (\$000)	(8) EFFECTIVE NET PROGRAM FUEL SAVINGS (\$000)
2008	0	0	3	3	0	0	0	42
2009	0	0	3	3	0	0	0	84
2010	0	0	3	3	0	0	0	82
2011	0	0	3	3	0	0	0	74
2012	0	0	3	3	0	0	0	84
2013	0	0	3	3	0	0	0	87
2014	0	0	3	3	0	0	0	112
2015	0	0	3	3	0	0	0	116
2016	0	0	3	3	0	0	0	111
2017	0	0	3	3	0	0	0	131
2018	0	0	3	3	0	0	0	125
2019	0	0	3	3	0	0	0	128
2020	0	0	3	3	0	0	0	131
2021	0	0	3	3	0	0	0	130
2022	0	0	3	3	0	0	0	143
2023	0	0	3	3	0	0	0	147
2024	0	0	3	3	0	0	0	154
2025	0	0	3	3	0	0	0	158
2026	0	0	3	3	0	0	0	166
2027	0	0	3	3	0	0	0	171
NOMINAL	0	59	59	0	0	0	0	2,377
NPV	0	34	34	0	0	0	0	1,205

WORKSHEET: FUEL SAVINGS WORKSHEET
PROGRAM: COMMERCIAL ENERGY AUDIT (14C-AUDIT)

(1) YEAR	(2) ON-PEAK KWH GENERATION REDUCTION (000)	(3) AVOIDED ON-PEAK MARGINAL FUEL COST (\$000)	(4) OFF-PEAK KWH GENERATION INCREASE (000)	(5) INCREASED OFF-PEAK MARGINAL FUEL COST (\$000)	(6) NET AVOIDED PROGRAM FUEL SAVINGS (\$000)	(7) EFFECTIVE NET AVOIDED FUEL SAVINGS (\$000)
2008	927	42	0	0	42	42
2009	1,854	84	0	0	84	84
2010	1,854	82	0	0	82	82
2011	1,854	74	0	0	74	74
2012	1,854	84	0	0	84	84
2013	1,854	87	0	0	87	87
2014	1,854	112	0	0	112	112
2015	1,854	116	0	0	116	116
2016	1,854	111	0	0	111	111
2017	1,854	131	0	0	131	131
2018	1,854	125	0	0	125	125
2019	1,854	128	0	0	128	128
2020	1,854	131	0	0	131	131
2021	1,854	130	0	0	130	130
2022	1,854	143	0	0	143	143
2023	1,854	147	0	0	147	147
2024	1,854	154	0	0	154	154
2025	1,854	158	0	0	158	158
2026	1,854	166	0	0	166	166
2027	1,854	171	0	0	171	171
NOMINAL	36,152	2,377	0	0	2,377	2,377
NPV		1,205	0	0	1,205	1,205

WORKSHEET: UTILITY AND PARTICIPANT DSM COSTS
PROGRAM: COMMERCIAL ENERGY AUDIT (14C-AUDIT)

(1) YEAR	(2) UTILITY NONREC. COSTS (\$000)	(3) UTILITY RECUR. COSTS (\$000)	(4) TOTAL UTILITY PROG. COSTS (\$000)	(5) UTILITY NONREC. REBATE/ INCENT. (\$000)	(6) UTILITY RECUR. REBATE/ INCENT. (\$000)	(7) TOTAL UTILITY REBATE/ INCENT. (\$000)	(8) PARTIC. CUST. EQUIP. COSTS (\$000)	(9) PARTIC. CUST. O&M COSTS (\$000)	(10) TOTAL PARTIC. CUST. COSTS (\$000)
2008	150	0	150	0	0	0	420	0	420
2009	0	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0	0
2011	0	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0	0
2013	169	0	169	0	0	0	473	0	473
2014	0	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0
2018	190	0	190	0	0	0	532	0	532
2019	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0
2023	214	0	214	0	0	0	599	0	599
2024	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0
NOMINAL	723	0	723	0	0	0	2,025	0	2,025
NPV	445	0	445	0	0	0	1,245	0	1,245

WORKSHEET: REVENUE LOSS/GAIN
PROGRAM: COMMERCIAL ENERGY AUDIT (14C-AUDIT)

(1) YEAR	(2) CUSTOMER BILL KWH REDUCTION (000)	(3) CUST. BILL REDUCT. FUEL PORTION (\$000)	(4) CUST. BILL REDUCT. NONFUEL PORTION (\$000)	(5) TOTAL ELECTRIC REVENUE REDUCT. (\$000)	(6) EFFECTIVE ELECTRIC REVENUE REDUCT. (\$000)	(7) CUSTOMER BILL KWH INCREASE (\$000)	(8) CUST. BILL INCR. FUEL PORTION (\$000)	(9) CUST. BILL INCR. NONFUEL PORTION (\$000)	(10) TOTAL ELECTRIC REVENUE INCR. (\$000)	(11) EFFECTIVE ELECTRIC REVENUE INCR. (\$000)	(12) EFFECTIVE NAT GAS REVENUE INCR. (\$000)
2008	825	21	52	72	72	0	0	0	0	0	0
2009	1,650	38	105	143	143	0	0	0	0	0	0
2010	1,650	50	107	157	157	0	0	0	0	0	0
2011	1,650	35	109	144	144	0	0	0	0	0	0
2012	1,650	22	110	132	132	0	0	0	0	0	0
2013	1,650	23	112	135	135	0	0	0	0	0	0
2014	1,650	24	114	137	137	0	0	0	0	0	0
2015	1,650	24	115	139	139	0	0	0	0	0	0
2016	1,650	25	117	143	143	0	0	0	0	0	0
2017	1,650	26	119	145	145	0	0	0	0	0	0
2018	1,650	27	121	148	148	0	0	0	0	0	0
2019	1,650	28	123	151	151	0	0	0	0	0	0
2020	1,650	31	125	156	156	0	0	0	0	0	0
2021	1,650	30	127	157	157	0	0	0	0	0	0
2022	1,650	34	129	163	163	0	0	0	0	0	0
2023	1,650	35	131	166	166	0	0	0	0	0	0
2024	1,650	37	133	170	170	0	0	0	0	0	0
2025	1,650	40	135	175	175	0	0	0	0	0	0
2026	1,650	43	137	180	180	0	0	0	0	0	0
2027	1,650	46	139	185	185	0	0	0	0	0	0
NOMINAL	32,175	638	2,359	2,996	0	0	0	0	0	0	0
NPV		351	1,269	1,619		0	0	0	0	0	0

UTILITY COST TEST
PROGRAM: COMMERCIAL ENERGY AUDIT (14C-AUDIT)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
YEAR	INCREASED SUPPLY COSTS (\$000)	UTILITY PROGRAM COSTS (\$000)	REBATES/ INCENT. (\$000)	OTHER COSTS (\$000)	TOTAL COSTS (\$000)	AVOIDED GEN UNIT BENEFITS (\$000)	AVOIDED T & D BENEFITS (\$000)	PROGRAM FUEL SAVINGS (\$000)	OTHER BENEFITS (\$000)	TOTAL BENEFITS (\$000)	NET BENEFITS (\$000)	CUMULATIVE DISCOUNTED NET BENEFITS (\$000)
2008	0	150	0	0	150	0	0	3	42	0	45	(105)
2009	0	0	0	0	0	0	0	3	84	0	87	(24)
2010	0	0	0	0	0	0	0	3	82	0	85	50
2011	0	0	0	0	0	0	17	3	74	0	94	127
2012	0	0	0	0	0	0	11	3	84	0	98	202
2013	0	169	0	0	169	10	0	3	87	0	100	(69)
2014	0	0	0	0	0	0	(5)	3	112	0	110	153
2015	0	0	0	0	0	0	(7)	3	116	0	112	226
2016	0	0	0	0	0	0	(4)	3	111	0	111	296
2017	0	0	0	0	0	0	(15)	3	131	0	119	361
2018	0	190	0	0	190	(11)	0	3	125	0	116	(74)
2019	0	0	0	0	0	(13)	0	3	128	0	118	388
2020	0	0	0	0	0	(14)	0	3	131	0	119	444
2021	0	0	0	0	0	(14)	0	3	130	0	119	497
2022	0	0	0	0	0	(21)	0	3	143	0	120	546
2023	0	214	0	0	214	(23)	0	3	147	0	125	595
2024	0	0	0	0	0	(27)	0	3	154	0	127	(87)
2025	0	0	0	0	0	(29)	0	3	158	0	130	563
2026	0	0	0	0	0	(33)	0	3	166	0	132	607
2027	0	0	0	0	0	(36)	0	3	171	0	136	649
NOMINAL	0	723	0	0	723	(214)	59	2,377	0	2,222	1,499	
NPV	0	445	0	0	445	(67)	34	1,205	0	1,172	727	

Discount Rate:
 Benefit/Cost Ratio [col (11) / col (6)]:
 7.00%
 2.64

TOTAL RESOURCE COST TEST
PROGRAM: COMMERCIAL ENERGY AUDIT (14C-AUDIT)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
YEAR	INCREASED SUPPLY COSTS (\$000)	UTILITY PROGRAM COSTS (\$000)	PARTIC. PROGRAM COSTS (\$000)	OTHER COSTS (\$000)	TOTAL COSTS (\$000)	AVOIDED GEN UNIT BENEFITS (\$000)	AVOIDED T & D BENEFITS (\$000)	PROGRAM FUEL SAVINGS (\$000)	OTHER BENEFITS (\$000)	TOTAL BENEFITS (\$000)	NET BENEFITS (\$000)	CUMULATIVE DISCOUNTED NET BENEFITS (\$000)
2008	0	150	420	0	570	0	3	42	0	45	(525)	(525)
2009	0	0	0	0	0	0	3	84	0	87	87	(444)
2010	0	0	0	0	0	0	3	82	0	85	85	(370)
2011	0	0	0	0	0	17	3	74	0	94	94	(293)
2012	0	0	0	0	0	11	3	84	0	98	98	(218)
2013	0	169	473	0	642	10	3	87	0	100	(542)	(604)
2014	0	0	0	0	0	0	3	112	0	110	110	(531)
2015	0	0	0	0	0	0	3	116	0	112	112	(461)
2016	0	0	0	0	0	0	3	111	0	111	111	(397)
2017	0	0	0	0	0	(15)	3	131	0	119	119	(332)
2018	0	190	532	0	723	(11)	3	125	0	116	116	(606)
2019	0	0	0	0	0	(13)	3	128	0	118	118	(584)
2020	0	0	0	0	0	(14)	3	131	0	119	119	(531)
2021	0	0	0	0	0	(14)	3	130	0	120	120	(481)
2022	0	0	0	0	0	(21)	3	143	0	125	125	(433)
2023	0	214	599	0	814	(23)	3	147	0	127	(686)	(682)
2024	0	0	0	0	0	(27)	3	154	0	130	130	(638)
2025	0	0	0	0	0	(29)	3	158	0	132	132	(596)
2026	0	0	0	0	0	(33)	3	166	0	136	136	(556)
2027	0	0	0	0	0	(36)	3	171	0	138	138	(516)
NOMINAL	0	723	2,025	0	2,748	(214)	59	2,377	0	2,222	(526)	
NPV	0	445	1,245	0	1,690	(67)	34	1,205	0	1,172	(518)	

Benefit/Cost Ratio [col (11) / col (6)]

Discount Rate:

7.00%

0.69

RATE IMPACT TEST
PROGRAM: COMMERCIAL ENERGY AUDIT (14C-AUDIT)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
YEAR	INCREASED SUPPLY COSTS (\$'000)	UTILITY PROGRAM COSTS (\$'000)	REBATES/ INCENT. (\$'000)	ELECTRIC REVENUE LOSSES (\$'000)	OTHER COSTS (\$'000)	TOTAL COSTS (\$'000)	AVOIDED GEN UNIT & FUEL BENEFITS (\$'000)	AVOIDED T & D BENEFITS (\$'000)	ELECTRIC REVENUE GAINS (\$'000)	NAT GAS REVENUE GAINS (\$'000)	OTHER BENEFITS (\$'000)	TOTAL BENEFITS (\$'000)	NET BENEFITS TO ALL CUSTOMERS (\$'000)	CUMULATIVE DISCOUNTED NET BENEFIT (\$'000)
2008	0	150	0	72	0	222	42	3	0	0	0	45	(178)	(178)
2009	0	0	0	143	0	143	84	3	0	0	0	87	(56)	(230)
2010	0	0	0	157	0	157	82	3	0	0	0	85	(72)	(293)
2011	0	0	0	144	0	144	91	3	0	0	0	94	(50)	(334)
2012	0	0	0	132	0	132	96	3	0	0	0	98	(34)	(360)
2013	0	169	0	135	0	303	97	3	0	0	0	100	(204)	(505)
2014	0	0	0	137	0	137	107	3	0	0	0	110	(27)	(523)
2015	0	0	0	139	0	139	109	3	0	0	0	112	(27)	(539)
2016	0	0	0	143	0	143	108	3	0	0	0	111	(32)	(568)
2017	0	0	0	145	0	145	116	3	0	0	0	119	(26)	(572)
2018	0	190	0	148	0	338	113	3	0	0	0	116	(222)	(685)
2019	0	0	0	151	0	151	115	3	0	0	0	118	(33)	(701)
2020	0	0	0	156	0	156	116	3	0	0	0	119	(36)	(717)
2021	0	0	0	157	0	157	117	3	0	0	0	120	(38)	(732)
2022	0	0	0	163	0	163	122	3	0	0	0	125	(38)	(747)
2023	0	214	0	166	0	380	124	3	0	0	0	127	(253)	(839)
2024	0	0	0	170	0	170	127	3	0	0	0	130	(40)	(852)
2025	0	0	0	175	0	175	129	3	0	0	0	132	(43)	(866)
2026	0	0	0	180	0	180	133	3	0	0	0	136	(44)	(879)
2027	0	0	0	185	0	185	135	3	0	0	0	138	(47)	(892)
NOMINAL	0	723	0	2,998	0	3,721	2,163	59	0	0	0	2,222	(1,499)	
NPV	0	445	0	1,619	0	2,064	1,139	34	0	0	0	1,172	(892)	
Benefit / Cost Ratio [col (13) / col (7)]:				7.00%										
Discount rate:				0.5%										

PARTICIPANT COSTS AND BENEFITS
 PROGRAM: COMMERCIAL ENERGY AUDIT (14C-AUDIT)

(1) YEAR	(2) SAVINGS IN PARTICIPANT ELEC. BILL (\$000)	(3) PARTIC. TAX CREDITS (\$000)	(4) UTILITY REBATES/ INCENT. (\$000)	(5) OTHER PARTIC. BENEFITS (\$000)	(6) TOTAL PARTIC. BENEFITS (\$000)	(7) INCREASE IN PARTICIPANT GAS BILL (\$000)	(8) PARTIC. EQUIP. COSTS (\$000)	(9) PARTIC. O & M COSTS (\$000)	(10) OTHER PARTIC. COSTS (\$000)	(11) TOTAL COSTS (\$000)	(12) NET BENEFITS (\$000)	(13) CUMULATIVE DISCOUNTED NET BENEFITS (\$000)
2008	72	0	0	0	72	0	420	0	0	420	(348)	(348)
2009	143	0	0	0	143	0	0	0	0	0	143	(214)
2010	157	0	0	0	157	0	0	0	0	0	157	(77)
2011	144	0	0	0	144	0	0	0	0	0	144	41
2012	132	0	0	0	132	0	0	0	0	0	132	142
2013	135	0	0	0	135	0	473	0	0	473	(338)	(100)
2014	137	0	0	0	137	0	0	0	0	0	137	(8)
2015	139	0	0	0	139	0	0	0	0	0	139	78
2016	143	0	0	0	143	0	0	0	0	0	143	162
2017	145	0	0	0	145	0	0	0	0	0	145	240
2018	148	0	0	0	148	0	532	0	0	532	(384)	45
2019	151	0	0	0	151	0	0	0	0	0	151	116
2020	156	0	0	0	156	0	0	0	0	0	156	186
2021	157	0	0	0	157	0	0	0	0	0	157	251
2022	163	0	0	0	163	0	0	0	0	0	163	314
2023	166	0	0	0	166	0	599	0	0	599	(433)	157
2024	170	0	0	0	170	0	0	0	0	0	170	215
2025	175	0	0	0	175	0	0	0	0	0	175	270
2026	180	0	0	0	180	0	0	0	0	0	180	323
2027	185	0	0	0	185	0	0	0	0	0	185	374
NOMINAL	2,998	0	0	0	2,998	0	2,025	0	0	2,025	973	
NPV	1,619	0	0	0	1,619	0	1,245	0	0	1,245	374	

In service year of generation unit:
 Discount rate:

2011
 7.00%